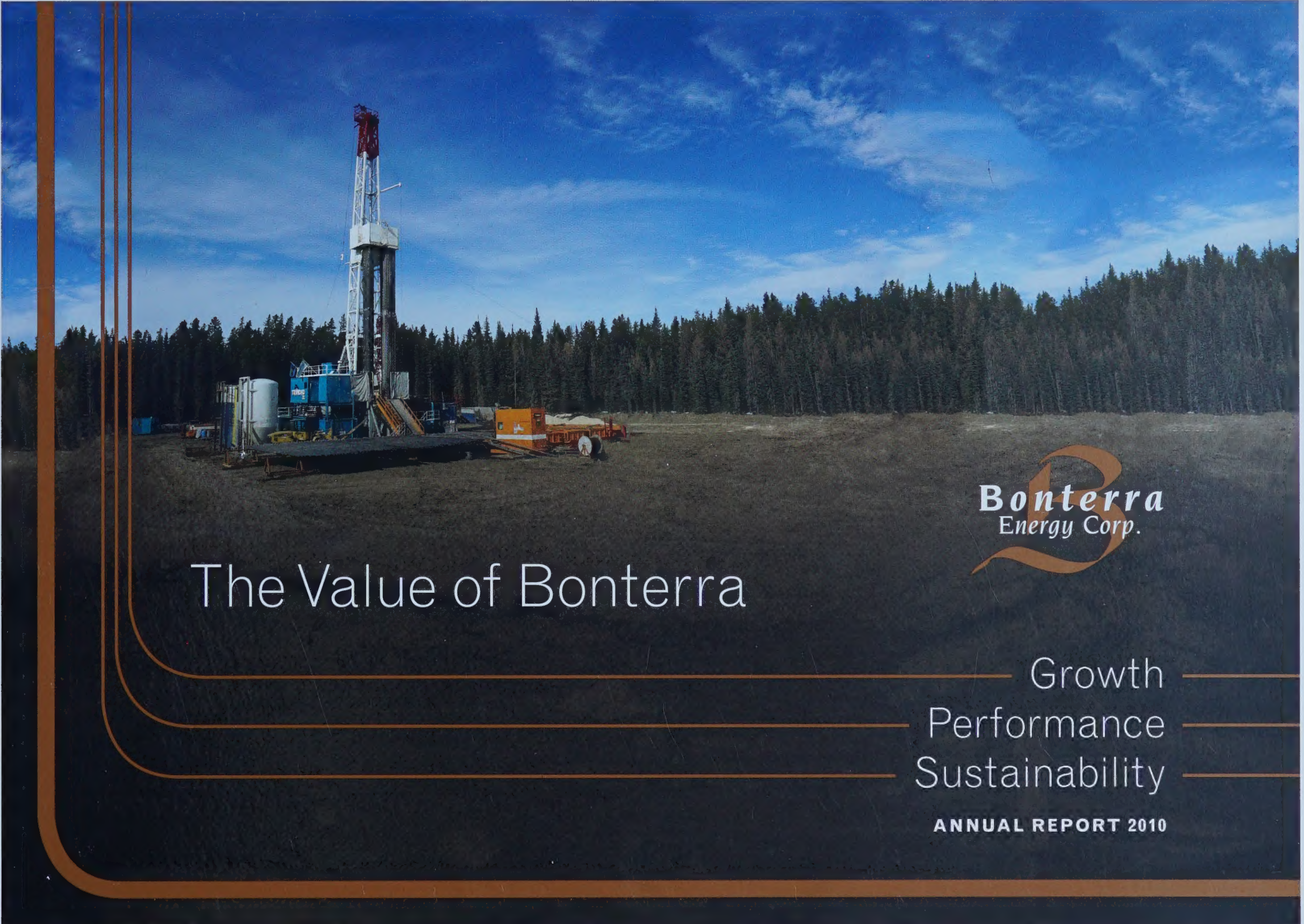


Bonterra Energy Corp.

The Value of Bonterra

Growth

Performance

Sustainability

ANNUAL REPORT 2010

Bonterra Energy Corp. is a high-yield, dividend paying oil and gas company headquartered in Calgary, Alberta with a proven history of creating growth and long-term value for shareholders on a per share basis. Bonterra's successful performance is due to its experienced management team, conservative capital structure and sustainable pace of development. The Company's operations are currently focused on creating value through the execution of its Cardium horizontal drill program and efficient operating practices, resulting in superior returns for investors.

Bonterra's common shares trade on the Toronto Stock Exchange under the ticker symbol **BNE.**

GROWTH

Bonterra is focused on providing investors with continued superior growth on both a total and per share basis. Bonterra's asset base consists of stable, producing properties located mainly in the Pembina field in central Alberta and are characterized by a long reserve life and low risk, predictable returns. The success of the Company's Cardium horizontal drill program will continue to drive future growth and maximize long-term value for shareholders.

PERFORMANCE

Bonterra provides income in the form of a monthly dividend and has consistently generated strong returns for investors. The Company has over $436 million in tax pools which currently extends Bonterra's tax horizon past 2018, allowing the Company to target a 2011 payout ratio of 55 to 70 percent of funds flow.

SUSTAINABILITY

Bonterra is focused on the sustainable development and efficient management of its high-quality, low-risk asset base. By operating approximately 84 percent of its production, Bonterra maintains a high degree of control over the pace of its capital development program and costs incurred. The Company spent $76.9 million in 2010 and drilled 22 gross (20.0 net) wells with a 100 percent success rate.

5,628 BOE PER DAY IN 2010	**8%** INCREASE IN PRODUCTION PER SHARE	See page 4 for more info
39.4 MILLION BOE OF P+P RESERVES	**5%** INCREASE IN P+P RESERVES ON A PER SHARE BASIS	See page 12 for more info
59% ONE-YEAR TOTAL RETURN	**$1.2** BILLION MARKET CAP	See page 4 for more info
$2.55 PAID OUT PER SHARE IN 2010	**$79.6** MILLION FUNDS FLOW	See page 5 for more info
14 YEAR DRILLING INVENTORY	**420** GROSS DRILLING LOCATIONS	See page 9 for more info
77% OF P+P RESERVES WEIGHTED TO CRUDE OIL/LIQUIDS	**17.8** YEAR RLI (PROVED PLUS PROBABLE)	See page 12 for more info

ANNUAL HIGHLIGHTS

Funds Flow increased **20%** in 2010.

Find out more on page 5

A **50%** increase in dividends paid year over year.

Find out more on page 6

69% of production in 2010 was oil/liquids.

Find out more on page 26

Financial ($000s, except $ per share)	**2010**	2009	2008
Revenue – realized oil and gas	**118,980**	85,712	121,730
Funds Flow [(1)]	**79,602**	66,504	70,448
Per share basic	**4.23**	3.69	4.13
Per share diluted	**4.12**	3.67	4.12
Payout ratio	**60%**	46%	76%
Cash flow from operations	**66,262**	38,893	69,570
Per share basic	**3.52**	2.16	4.07
Per share diluted	**3.42**	2.15	4.06
Payout ratio [(2)]	**72%**	79%	77%
Cash payments per share [(2)]	**2.55**	1.70	3.12
Net earnings [(3)]	**49,864**	68,563	55,426
Per share basic	**2.65**	3.81	3.25
Per share diluted	**2.58**	3.78	3.23
Capital expenditures and acquisitions (net of disposals)	**70,680**	5,640	45,407
Total assets	**335,144**	293,987	265,301
Working capital deficiency	**14,602**	10,162	23,878
Long-term debt	**85,386**	59,823	79,910
Shareholders' equity	**138,413**	118,874	56,777
Operations			
Oil and liquids (barrels per day)	**3,875**	3,141	3,073
Natural gas (MCF per day)	**10,521**	11,120	7,637
Total BOE per day	**5,628**	4,994	4,346

QUARTERLY HIGHLIGHTS

2010	4th	3rd	2nd	1st
Financial ($000s, except $ per share)				
Revenue – realized oil and gas	**34,209**	28,332	29,191	27,248
Funds Flow (1)	**21,104**	19,622	17,550	21,326
Per share basic	**1.11**	1.04	0.94	1.14
Per share diluted	**1.08**	1.01	0.91	1.11
Payout ratio	**61%**	63%	68%	50%
Cash flow from operations	**16,987**	17,558	16,644	15,073
Per share basic	**0.89**	0.93	0.89	0.81
Per share diluted	**0.86**	0.91	0.86	0.79
Payout ratio (3)	**74%**	71%	72%	70%
Cash dividends per share (2)	**0.68**	0.66	0.64	0.57
Net earnings	**14,213**	12,724	10,887	12,040
Per share basic	**0.75**	0.68	0.58	0.64
Per share diluted	**0.73**	0.66	0.56	0.63
Capital expenditures and acquisitions (net of disposals)	**25,318**	19,227	10,994	15,141
Total assets	**335,144**	318,493	307,934	305,440
Working capital deficiency	**14,602**	17,891	2,281	13,178
Long-term debt	**85,386**	73,901	78,434	63,097
Shareholders' equity	**138,413**	128,492	126,045	125,392
Operations				
Oil and liquids (barrels per day)	**4,378**	3,890	3,874	3,345
Natural gas (MCF per day)	**10,214**	10,674	11,157	10,038
Total BOE per day	**6,080**	5,669	5,733	5,018

(1) Funds flow is not a recognized measure under GAAP. For these purposes, the Company defines funds flow as funds provided by operations before changes in non-cash operating working capital items but including gain on sale of property and investments, adjustments of investment tax credit receivable and excluding restricted cash and asset retirement obligations settled.

(2) Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

(3) Net earnings includes gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2010 - $10,820,000, 2009 - $51,868,000, 2008 - $Nil).

Bonterra met its 2010 target payout ratio of between **60 and 75%** of Funds Flow.

Find out more on page 6

Q4 2010 production increased **24%** compared to Q4 2009.

Find out more on page 26

REPORT TO SHAREHOLDERS

Production per Share/Unit
(BOE)

Reserves per Share/Unit
(Proved plus Probable)

Bonterra Energy Corp. ("Bonterra" or the "Company") is pleased to report to shareholders its operational and financial results for the year ended December 31, 2010. The Company continues to maintain that the best assessment of an entity is its long-term return to shareholders. In 2010, Bonterra provided investors with a **total return of 59 percent** and continued to perform extremely well over longer periods of time. Total return to shareholders over a three year period (2008 – 2010) was 176 percent and over a five year period (2006 – 2010) was 205 percent. These positive results are mainly attributable to the Company's success in the development of its Cardium horizontal drilling program.

It is a long-term outlook that defines Bonterra's business strategy. The Company provides investors with stable income in the form of a monthly dividend and the potential of appreciation of its share price by sustainable annual growth through the internal development and expansion of its high-quality asset base.

GROWTH AND PERFORMANCE

Bonterra has been a leader in applying horizontal, multi-stage frac technology in the Pembina Cardium field having **drilled the first well in the halo area** in 2008. The Company has continued to aggressively develop its Cardium opportunities in 2010 recording its best operational results to date.

2010 highlights include:

- Drilled 22 gross (20.0 net) operated Cardium horizontal, multi-stage fractured wells with a **100 percent success rate** in the halo area.
- Participated in 5 gross (0.75 net) **successful non-operated Cardium horizontal, multi-stage fractured wells in the main Pembina Cardium pool.**
- Average daily **production increased by 13 percent** to 5,628 BOE per day.
- **Production per share increased by 8 percent** to 0.109 BOE per share.
- Total Proved plus Probable **reserves increased by 10 percent** to 39.4 million BOE.
- Total Proved plus Probable **reserves per share increased by 5 percent** to 2.09 BOE per share.
- Total Proved **reserves increased by 13 percent** to 28.6 million BOE.

- Proved plus Probable **reserve adds 2.7 times 2010 production.**
- Proved plus Probable **reserve life index of 17.8 years,** one of the highest among conventional producers.

In 2011, Bonterra plans to invest between $50 to $60 million on its development program focusing capital and technical staff on the Company's highest-quality opportunities. The program plan is to:

- **Drill a minimum of 20 gross horizontal Cardium wells** mainly in the halo area of the Pembina and Willesden Green fields with the remainder in the main pool of the Pembina field.
- Maintain a steady pace of development targeting **10 to 15 percent growth** in production. Production for the full year 2011 is estimated to be between 6,200 to 6,500 BOE per day.
- Implement further cost reduction initiatives on the horizontal drill program including new drilling and completion methods to not only decrease costs but also **improve well performance and reserve recovery.**
- Conduct project reviews throughout the year and apply additional operational efficiencies where possible to **reduce operating costs** to the $12.50 to $13.50 per BOE range.
- Continue to review and **develop new opportunities** to ensure long-term sustainable growth.

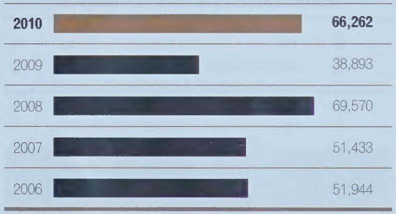
FINANCIAL RESULTS

Financial results in 2010 were positively impacted by increased production levels and improved crude oil prices. Overall, Bonterra generated **cash flow from operations of $66.3 million** and net earnings of $49.9 million or on a per share basis (basic), $3.52 and $2.65, respectively. The Company's average realized price for crude oil and natural gas liquids increased 21.5 percent year over year to $72.69 per barrel. Natural gas prices remained depressed and the Company's average realized price was $4.14 per MCF.

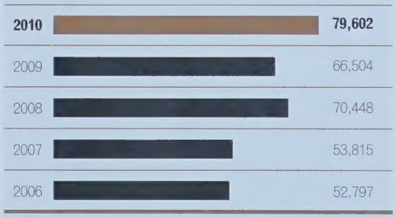
The improved crude oil pricing environment is positive for the Company. Bonterra's production is composed of predominantly light oil and in 2010, **69 percent of the Company's production was crude oil and liquids.** The Board of Directors and management have decided to not engage in any hedging practices at the present time and have not hedged since 2008.

Average Daily Production
(BOE per day)

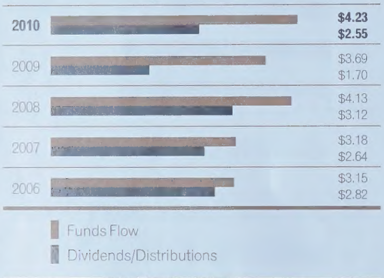
Cash Flow from Operations
($ thousands)



Funds Flow
($ thousands)



Cash Dividends/Distributions to Investors
($ per unit/share)



In 2010, Bonterra increased the monthly cash dividend twice and paid out a total of $2.55 per share, an increase of 50 percent over 2009 levels. Subsequent to year-end, Bonterra was able to again **increase the dividend to its current level of $0.24 per share** which began with the dividend paid out in January 2011.

Management and the Board of Directors will continue to monitor production volumes, commodity prices, operating costs, payout ratios and capital expenditures on a monthly basis to determine the dividend amount. There remains good potential to increase the dividend level should the current strong pricing environment persist coupled with expected production level increases resulting from the capital program.

FINANCIAL STRENGTH

A conservative approach to the Company's capital structures has been a key factor in building financial strength and flexibility. Bonterra retains its strong financial position by maintaining a sustainable growth strategy, minimizing the amount and cost of debt and raising equity when prudent. As a result, Bonterra is well funded to execute the 2011 capital program and to pursue additional acquisition opportunities that may become available.

Bonterra has over $436 million in tax pools, $27 million in investment tax credits and $141 million of capital loss carry forwards (which can only be claimed against taxable capital gains). The Company anticipates that these pools push Bonterra's **tax horizon beyond 2018.**

The Company ended 2010 with a total of debt and working capital to cash flow ratio of 1.18 times (based on a total of debt and working capital of $100.0 million and annualized 2010 fourth quarter funds flow of $84.4 million). As a result of its strong financial position, Bonterra is well funded to execute the 2011 capital program and to pursue additional acquisition opportunities that may become available.

ACQUISITIONS AND DISPOSITIONS

Bonterra has strengthened its asset base by selling a portion of its non-core holdings. In February 2010, the Company disposed of its Southeast Saskatchewan Pinto property. The proceeds of disposition were $5,534,000 cash. In addition, during the third quarter of 2010 the Company disposed of non-producing land for proceeds of $700,000. The Company **re-deployed the proceeds from these dispositions towards Bonterra's 2010 Cardium drilling program.**

Bonterra's core asset base is concentrated in the Cardium pools located in the Pembina and Willesden Green fields of west central Alberta. The Company's high level of concentration and experience in the area provides Bonterra with the knowledge to efficiently exploit the Cardium formation. As such, Bonterra plans to pursue land and corporate acquisitions to acquire further interests in its key resource plays. In addition, Bonterra is also considering natural gas acquisitions to take advantage of the low price environment. Bonterra's **enviable, mainly oil, drilling inventory of over 14 years** may allow the Company to acquire natural gas assets at low prices and to wait until natural gas pricing improves before developing these properties.

OUTLOOK

This is an exciting time for Bonterra and its shareholders. The Company has a **superior inventory of long-life, light oil targets in the Cardium play and the flexibility to allocate internal resources to achieve the best returns.** The Company will continue to execute a disciplined approach to its operations and financial management in 2011 to maximize shareholder value on a long-term basis while remaining committed to continuous improvements and safety across its operations.

The Company is confident that 2011 will be a year of growth for both its operations and its investors. Bonterra would like to take this opportunity to thank its long-term shareholders for their continued support of the Company, the Board of Directors for their strategic guidance and its employees for continuing to create and deliver outstanding value for shareholders.

George F. Fink
Chairman of the Board and Chief Executive Officer

Randy M. Jarock
President and Chief Operating Officer

Proved plus Probable Reserves
(MBOE)

Proved plus Probable Reserve Life Index
(years)

> *Bonterra's demonstrated history of year over year reserve and production growth on a per share basis is unparalleled in the energy industry. Growth on a per share basis will remain a prime objective for Bonterra.*

14 year

DRILLING INVENTORY

10%-15%

PRODUCTION GROWTH TARGET FOR 2011

OPERATIONAL REVIEW

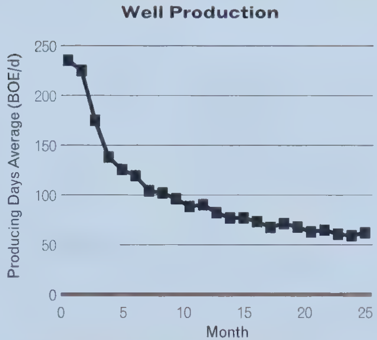
The enormous resource potential, robust economics and solid results recorded by Bonterra in its horizontal Cardium drilling program continue to provide the Company with strong competitive advantages.

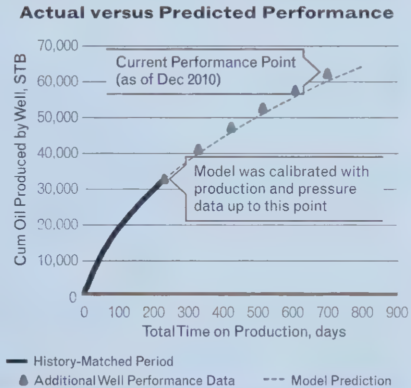
Bonterra drilled the first horizontal well (01-25-047-03W5) in the Pembina halo area in late 2008 which has averaged 101 BOE per producing day to date. This well has performed as expected, exhibiting a typical Cardium hyperbolic decline that is generally observed in the main Pembina Pool. The well has also tracked favorably with Sproule Associates Limited's predicted performance trend from the 3-D Reservoir Model that was completed in September, 2009. This 3-D numerical model indicates that oil recoveries of up to 225,000 stock tank barrels per well are achievable in portions of the Cardium halo with similar well completion and reservoir characteristics.

Bonterra's operations are defined by consistency and sustainability. Bonterra's demonstrated history of year over year reserve and production growth on a per share basis is unparalleled in the energy industry. Growth on a per share basis will remain a prime objective for Bonterra.

In 2011, Bonterra plans to drill at least 20 wells, predominantly in the halo area of the Pembina and Willesden Green Cardium fields with the remainder in the main pool of the Pembina Cardium field. The Company plans to continue advancing its use of horizontal multi-stage technology in the main part of the Pembina Cardium pool in 2011 by initiating an operated multi-well program in the second half of 2011 with the objective of changing the pool exploitation strategy to horizontal well development from vertical well development.

01-25-047-03W5



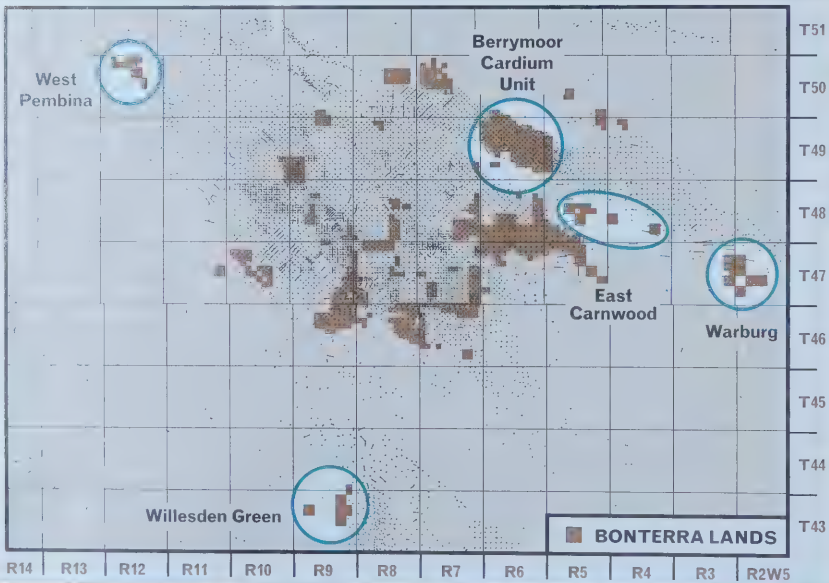


CARDIUM HORIZONTAL DRILLING

OVERVIEW

Bonterra is the third largest operator in the Pembina Cardium field, Canada's largest conventional light oil field, with approximately 160 gross (117 net) sections including 27.5 gross (23.9 net) sections in the halo area. Bonterra has a 14 year drilling inventory with 420 gross locations already identified including at least 52 gross horizontal locations in the Halo area of the Pembina and Willesden Green fields.

In 2011, the Company will spend \$50 to \$60 million on its capital development program focused mainly on its horizontal drill program. Full year production rates are expected to average between 6,200 to 6,500 BOE per day, an increase of 10 to 15 percent over 2010 levels.



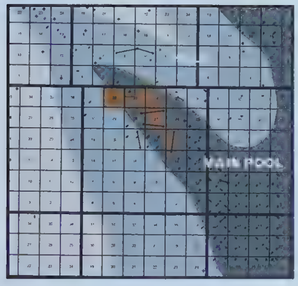
Main Pool

Bonterra participated in successfully drilling five gross (0.75 net) non-operated horizontal Berrymoor Cardium Unit wells in the main Pembina Cardium pool. The Company plans to further advance the use of horizontal multi-stage technology in 2011 with the objective of converting some identified vertical locations to horizontals locations.

- **98.4 gross (82.3 net) sections**
- **5 gross (0.75 net) wells drilled in 2010**
- **6 gross (2.9 net) wells planned in 2011**

West Pembina

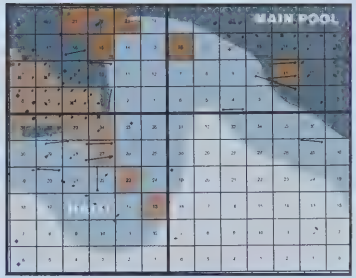
The West Pembina area was a key focus area for the Company in 2010. Bonterra's development plans in 2011 will involve completing development of the area to four wells per section.



- 4 gross (3.75 net) sections
- 12 wells drilled in 2010
- 4 gross (3 net) wells planned in 2011
- 278,310 Bbls of cumulative oil production (02/28/2011)
- 2,845.6 MBOE Proved reserves; 4,062.1 MBOE Proved plus Probable reserves

East Carnwood

Bonterra will look to follow up on the success of the 15-22 48 05W5 well in this area with its 2011 capital development program.



- 5.5 gross (4.375 net) sections
- 5 gross (4.25 net) wells drilled in 2010
- 5 gross wells (3.75 net) planned in 2011
- 93,157 Bbls of cumulative oil production (02/28/2011)
- 1,846 MBOE Proved; 3,139.6 MBOE Proved plus Probable reserves

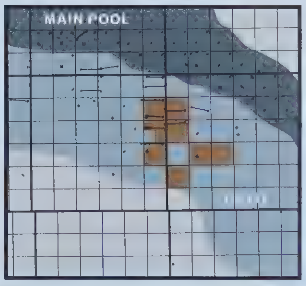
Willesden Green

This area provides the Company with a large potential for future reserve growth and will be an important component of the 2011 capital development program.

- 5 gross (4.875 net) sections
- 4 gross wells (3.75 net) drilled in 2010
- 5 gross (5 net) wells planned in 2011
- 17,211 Bbls of cumulative oil production (02/28/2011)
- 251.3 MBOE Proved; 838.1 MBOE Proved plus Probable reserves

Warburg

Bonterra has recorded success in this area, the initial area of development. It has demonstrated potential for low risk and repeatable infill development.



- 7.75 gross (5.3 net) sections
- 3 gross (2.0 net) wells drilled in 2010
- 2 gross (1.4 net) wells planned in 2011
- 354,075 Bbls of cumulative oil production (02/28/2011)
- 1,409 MBOE Proved; 2,197 MBOE Proved plus Probable reserves

* Drilling plans are subject to change based on actual results.

STATISTICAL REVIEW

RESERVES

Bonterra engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2010. The reserves are located in the provinces of Alberta, British Columbia and Saskatchewan. Bonterra's largest producing area is located in the Pembina and Willesden Green fields of Alberta, which contains 94.3 percent of the Company's reserves of a Proved plus Probable basis. The gross reserve figures from the following tables represent Bonterra's ownership interest before royalties and before consideration of the Company's royalty interests. Tables may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2010

Reserve Category:	Light and Medium Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	BOE[1] (MBOE)
Proved				
Developed Producing	15,594.4	32,552	1,400.7	22,420.3
Developed Non-Producing	206.1	507	12.6	303.3
Undeveloped	4,693.0	5,441	251.7	5,851.4
Total Proved	20,493.5	38,500	1,665.0	28,575.1
Probable	7,708.2	15,192	581.7	10,822.0
Total Proved Plus Probable	28,201.7	53,692	2,246.7	39,397.0

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2010

	Light and Medium Oil and Natural Gas Liquids		Natural Gas		BOE[1]	
	Proved (Mbbl)	Proved plus Probable (Mbbl)	Proved (MMcf)	Proved plus Probable (MMcf)	Proved (MBOE)	Proved Plus Probable (MBOE)
December 31, 2009	19,220.1	27,567.7	36,642	49,539	25,327.1	35,824.2
Extension	2,984.1	4,915.8	2,706	4,374	3,435.1	5,644.8
Improved Recovery	0	0	0	0	0	0
Technical Revisions	1,474.1	(489.9)	3,512	4,193	2,059.4	208.9
Discoveries	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0
Dispositions	(178.9)	(213.3)	(318)	(376)	(231.9)	(276.0)
Economic factors	73.5	82.5	(202)	(198)	39.8	49.5
Production	(1,414.4)	(1,414.4)	(3,840)	(3,840)	(2,054.4)	(2,054.4)
December 31, 2010	22,158.5	30,448.4	38,500	53,692	28,575.2	39,397.1

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2010

Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/Year)

($ Millions) Reserve Category:	0%	5%	10%	15%	20%	Future Net Value 10%/yr ($/BOE)[1]
Proved						
Developed Producing	1,097.7	656.9	479.9	385.3	326.0	24.15
Developed Non-Producing	14.4	10.7	8.6	7.2	6.2	31.65
Undeveloped	207.1	135.8	93.1	65.4	46.5	18.85
Total Proved	1,319.2	803.5	581.6	457.9	378.7	23.19
Probable	644.5	251.8	132.1	82.0	56.1	14.58
Total Proved Plus Probable	1,963.7	1,055.2	713.6	540.0	434.8	20.91

Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/Year)

($ Millions) Reserves Category:	0%	5%	10%	15%	20%
Proved					
Developed Producing	929.5	585.3	441.9	362.7	311.5
Developed Non-Producing	10.8	8.3	6.8	5.8	5.2
Undeveloped	155.3	100.3	67.4	46.1	31.6
Total Proved	1,095.5	693.9	516.1	414.7	348.2
Probable	483.5	188.5	98.7	61.2	41.9
Total Proved Plus Probable	1,579.0	882.3	614.8	475.9	390.1

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per BBl)	Natural Gas AECO-C-Spot (Cdn $ per MMbtu)	Butanes Edmonton (Cdn $ per Bbl)	Pentanes Edmonton (Cdn $ per Bbl)	Inflation Rate (%/Yr)	Exchange Rate ($ U.S./$ Cdn)
2011	93.08	4.04	62.44	95.32	1.5	0.932
2012	93.85	4.66	62.95	96.11	1.5	0.932
2013	93.43	4.99	62.67	95.68	1.5	0.932
2014	93.54	6.58	62.75	95.79	1.5	0.932
2015	94.95	6.69	63.69	97.24	1.5	0.932
2016	96.38	6.80	64.65	98.71	1.5	0.932
2017	97.84	6.91	65.63	100.20	1.5	0.932
2018	99.32	7.02	66.62	101.71	1.5	0.932
2019	100.81	7.14	67.63	103.25	1.5	0.932
2020	102.34	7.26	68.65	104.81	1.5	0.932

Crude oil, natural gas and liquid prices escalate at 1.5 percent thereafter.

2010 FINDING AND DEVELOPMENT COSTS

The Company has historically been active in its capital development program. Over three years, Bonterra has incurred the following finding and development (F&D) and finding, development and acquisition(FD&A)[3] costs:

	2010 F&D Costs per BOE[1][2]	2009 F&D Costs per BOE[1][2]	2008 F&D Costs per BOE[1][2]	Three Year Average
Proved Reserve Net Additions	**$ 21.98**	$ 16.23	$ 7.00	$ 15.07
Proved plus Probable Reserve Net Additions	**$ 19.19**	$ 11.01	$ 6.82	$ 12.34

	2010 FD&A Costs per BOE[1][2][3]	2009 FD&A Costs per BOE[1][2][3]	2008 FD&A Costs per BOE[1][2][3]	Three Year Average
Proved Reserve Net Additions	**$ 20.86**	$ 13.25	$ 8.67	$ 14.26
Proved plus Probable Reserve Net Additions	**$ 18.13**	$ 8.93	$ 7.47	$ 11.51

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(3) FD&A costs are net of proceeds of disposal and the FD&A costs per BOE are based on reserves acquired net of reserves disposed of.

FD&A and F&D cost increases are primarily due to 1) a 12 percent increase to the Company's average horizontal well costs, reflecting the deeper Cardium targets in West Pembina and Willesden Green and the placing of more fracs per well; 2) capital for infrastructure which will reduce operating expense but not increase reserves was included that was not included in the previous reserve report; and 3) due to the 51-101 Standards of Disclosure only six of a possible 22 wells were assigned reserves in Willesden Green.

All reserves numbers provided in the preceding tables are Bonterra's interest before royalties. It should not be assumed that the estimates of future net revenue presented in the above tables represent the fair market value of reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

PRODUCTION

	2010		
	Oils and NGLs (Bbls per day)	Natural Gas (MCF per day)	Total (BOE per day)
Pembina, Alberta	3,564	6,607	4,665
British Columbia	22	2,971	517
Saskatchewan	172	269	217
Other Alberta	117	674	229
	3,875	10,521	5,628

LAND HOLDINGS

	2010		2009	
	Gross Acres	**Net Acres**	Gross Acres	Net Acres
Alberta	**172,749**	**109,944**	172,907	109,710
British Columbia	**61,330**	**21,217**	73,194	28,509
Saskatchewan	**6,881**	**5,640**	14,779	12,846
	240,960	**136,801**	260,880	151,065

PETROLEUM AND NATURAL GAS EXPENDITURES

The following table summarizes petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

($000s)	**2010**	2009
Land	**-**	5,184
Acquisitions	**-**	7,105
Disposals	**(6,234)**	(30,191)
Exploration and development costs	**76,914**	22,912
Net petroleum and natural gas capital expenditures	**70,680**	5,640

DRILLING HISTORY

The following tables summarize Bonterra's gross and net drilling activity and success:

	2010					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude oil	**30**	**22.09**	**-**	**-**	**30**	**22.09**
Natural gas	**1**	**0.11**	**-**	**-**	**1**	**0.11**
Dry	**-**	**-**	**-**	**-**	**-**	**-**
Total	**31**	**22.20**	**-**	**-**	**31**	**22.20**
Success rate	**100%**	**100%**	**-**	**-**	**100%**	**100%**

	2009					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	15.0	12.4	-	-	15.0	12.4
Natural gas	2.0	0.4	-	-	2.0	0.4
Dry	-	-	-	-	-	
Total	17.0	12.8	-	-	17.0	12.8
Success rate	100%	100%	-	-	100%	100%

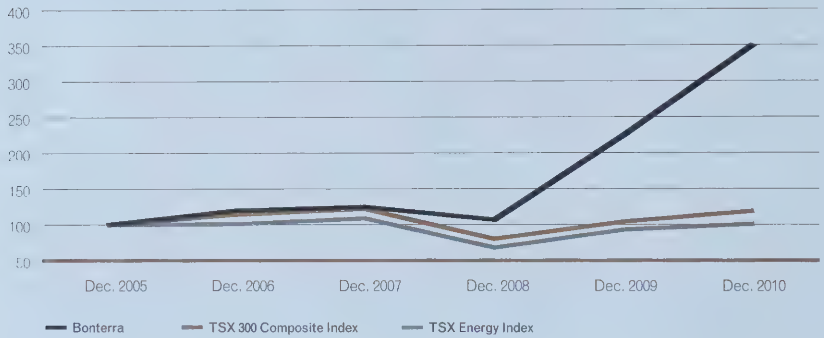
	2008					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	35.0	25.5	1	0.3	36.0	25.8
Natural gas	8.0	5.1	-	-	8.0	5.1
Dry	-	-	-	-	-	-
Total	43.0	30.6	1	0.3	44.0	30.9
Success rate	100%	100%	100%	100%	100%	100%

SHARE TRADING STATISTICS

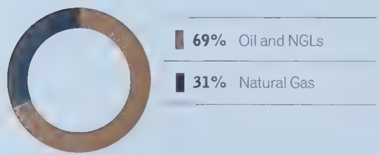
		2010		2009
High	$	**53.56**	$	36.44
Low	$	**31.27**	$	13.50
Close	$	**51.65**	$	35.14
Daily Average Trading Volume		**29,041**	$	22,704

BONTERRA VS. THE INDICES

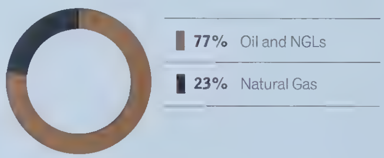
Cumulative Total Return on $100 Investment



2010 Production by Commodity



2010 Reserves by Commodity
(based on Proved plus Probable Reserves)



MANAGEMENT'S DISCUSSION AND ANALYSIS

This report dated March 22, 2011 is a review of the operations, current financial position, and outlook for Bonterra Energy Corp. ("Bonterra" or the "Company") and should be read in conjunction with the audited financial statements for the year ended December 31, 2010, together with the notes related thereto.

NON-GAAP MEASURES

Throughout this Management's Discussion and Analysis (MD&A) we use the terms "payout ratio" and "cash netback" to analyze operating performance. We calculate payout ratio by dividing cash dividends to shareholders by cash flow from operating activities both of which are measures prescribed by GAAP which appear on our consolidated statements of cash flows. We calculate cash netback by dividing various operation and deficit statement items as determined by GAAP by total production on a barrel of oil equivalent basis.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, statements relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; dividends; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas companies to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive and are further discussed herein under the heading Business Prospects, Risks and Outlooks as well as in the Company's Annual Information Form filed on SEDAR at www.sedar.com.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits will be derived therefrom. Except as required by law, the Company disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

ANNUAL COMPARISONS

As at and for the years ended December 31,	**2010**	2009	2008
Financial ($000s, except $ per share)			
Revenue – realized oil and gas	**118,980**	85,712	121,730
Cash flow from operations	**66,262**	38,893	69,570
Per share basic	**3.52**	2.16	4.07
Per share diluted	**3.42**	2.15	4.06
Cash payments per share [1]	**2.55**	1.70	3.12
Payout ratio [1]	**72%**	79%	77%
Net earnings [2]	**49,864**	68,563	55,426
Per share basic	**2.65**	3.81	3.25
Per share diluted	**2.58**	3.78	3.23
Capital expenditures and acquisitions (net of disposals)	**70,680**	5,640	45,407
Total assets	**335,144**	293,987	265,301
Working capital deficiency	**14,602**	10,162	23,878
Long-term debt	**85,386**	59,823	79,910
Shareholders' equity	**138,413**	118,874	56,777
Operations			
Oil and liquids (barrels per day)	**3,875**	3,141	3,073
Natural gas (MCF per day)	**10,521**	11,120	7,637
Total BOE per day	**5,628**	4,994	4,346

(1) Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

(2) Net earnings includes gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2010 – $10,820,000, 2009 – $51,868,000, 2008 – $Nil)

QUARTERLY COMPARISONS

	2010			
Financial ($000s, except $ per share)	4th	3rd	2nd	1st
Revenue – realized oil and gas	34,209	28,332	29,191	27,248
Cash flow from operations	16,987	17,558	16,644	15,073
Per share basic	0.89	0.93	0.89	0.81
Per share diluted	0.86	0.91	0.86	0.79
Cash dividends per share (1)	0.68	0.66	0.64	0.57
Payout ratio (1)	74%	71%	72%	70%
Net earnings	14,213	12,724	10,887	12,040
Per share basic	0.75	0.68	0.58	0.64
Per share diluted	0.73	0.66	0.56	0.63
Capital expenditures and acquisitions (net of disposals)	25,318	19,227	10,994	15,141
Total assets	335,144	318,493	307,934	305,440
Working capital deficiency	14,602	17,891	2,281	13,178
Long-term debt	85,386	73,901	78,434	63,097
Shareholders' equity	138,413	128,492	126,045	125,392
Operations				
Oil and liquids (barrels per day)	4,378	3,890	3,874	3,345
Natural gas (MCF per day)	10,214	10,674	11,157	10,038
Total BOE per day	6,080	5,669	5,733	5,018

(1) Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

(2) Net earnings includes gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2010 – $10,820,000, 2009 – $51,868,000, 2008 – $Nil)

		2009		
Financial ($000s, except $ per share)	4th	3rd	2nd	1st
Revenue – realized oil and gas	24,946	20,965	20,501	19,300
Cash flow from operations	13,673	9,350	9,238	6,632
Per share basic	0.76	0.50	0.52	0.38
Per share diluted	0.75	0.50	0.52	0.38
Cash dividends per share (1)	0.50	0.44	0.40	0.36
Payout ratio (1)	66%	87%	77%	94%
Net earnings	52,136	5,790	4,544	6,093
Per share basic	2.88	0.32	0.26	0.35
Per share diluted	2.85	0.32	0.26	0.35
Capital expenditures and acquisitions (net of disposals)	(16,976)	17,660	2,255	2,701
Total assets	293,987	273,543	258,393	260,732
Working capital deficiency	10,162	14,455	13,989	14,909
Long-term debt	59,823	81,386	71,573	89,383
Shareholders' equity	118,874	74,025	72,332	56,377
Operations				
Oil and liquids (barrels per day)	3,182	3,084	3,029	3,268
Natural gas (MCF per day)	10,193	10,881	11,551	11,877
Total BOE per day	4,881	4,898	4,954	5,245

(1) Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

(2) Net earnings includes gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2010 - $10,820,000, 2009 – $51,868,000, 2008 – $Nil).

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures (DC&P) are defined under National Instrument 52-109 – Certification of Disclosure Controls in Issuers' Annual and Interim Filings (NI 52-109) as "…controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers as appropriate to allow timely decisions regarding required disclosure." The Company has conducted a review and evaluation of its DC&P, with the conclusion that as at December 31, 2010 the Company has an effective system of DC&P as defined under NI 52-109. In reaching this conclusion, the Company recognizes that two key factors must be and are present:

1. the Company is very dependent upon its advisors and consultants (principally its legal counsels) to assist in recognizing, interpreting, understanding and complying with the various securities regulations disclosure requirements; and
2. the Company has an active Board and management with open lines of communication.

Bonterra has a small staff with varying degrees of knowledge concerning the various regulatory disclosure requirements. In many circumstances, the various regulatory requirements are relatively new, subject to interpretation, and complex. The Company is not of sufficient size to justify a separate department or one or more staff member specialists in this area. Therefore the Company must rely upon its advisors/consultants to assist it and as such they form part of the disclosure controls and procedures.

Proper disclosure necessitates that a person not only be aware of the pertinent disclosure requirements, but must also be sufficiently involved in the affairs of the Company and/or receives the communication of information to assess any necessary disclosure requirements. Accordingly, it is essential that there be proper communication among those people who manage and govern the affairs of the Company, this being the Board of Directors and senior management. The Company believes this communication exists.

While Bonterra believes it has adequate DC&P in place, lapses in the disclosure controls and procedures could occur and/or errors could occur. Should such occur, the Company intends to take whatever steps it deems necessary to minimize the consequences thereof.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting (ICFR) are defined in NI 52-109 as "... a process designed by, or under the supervision of, an issuer's certifying officers and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's Generally Accepted Accounting Practices (GAAP) and includes those policies and procedures that:

1. pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;
2. are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and
3. are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements."

The Company has conducted a review and evaluation of its ICFR, with the conclusion that as of December 31, 2010, the Company's system of ICFR as defined under NI 52-109 is adequately designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. In addition, the Company has concluded that sufficient mitigating controls exist that the below mentioned weaknesses have resulted in no material impact on the Company's financial reporting or ICFR.

The control framework the Company used to design and evaluate its ICFR was the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In its evaluation, the Company identified certain weaknesses in internal controls over financial reporting:

1. due to the limited number of staff at the Company, it is not feasible to achieve the complete segregation of incompatible duties; and
2. due to the limited number of staff, the Company relies upon third parties as participants in the Company's internal controls over financial reporting.

The Company believes these weaknesses are mitigated by: the active involvement of senior management and the Board of Directors in the affairs of the Company; open lines of communication within the Company; the present levels of activities and transactions within the Company being readily transparent; the thorough review of the Company's financial statements by management, the Board of Directors and by the Company's auditors; and the establishment of a whistle-blower policy. Based on the above identified weaknesses, the Company has concluded that the Company's ICFR are ineffective. The mitigating factors will not necessarily prevent a misstatement occurring as a result of the aforesaid weaknesses in the Company's internal controls over financial reporting. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met. The Company has no plans for remediating the above weaknesses.

INTERNAL CONTROL CHANGES

The Company is required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", otherwise referred to as Canadian SOX (C-Sox). The 2010 certificate requires that the Company disclose in the MD&A any changes in the Company's internal control over financial reporting that occurred during the period that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting. The Company confirms that no such changes were made to the internal controls over financial reporting during 2010.

PRODUCTION

	Three Months Ended			Twelve Months Ended	
	December 31, 2010	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Crude oil and NGLs (barrels per day)	**4,378**	3,890	3,182	**3,875**	3,141
Natural gas (MCF per day)	**10,214**	10,674	10,193	**10,521**	11,120
Average BOE per day	**6,080**	5,669	4,881	**5,628**	4,994

Barrels of oil equivalent (BOE) are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

Bonterra's 2010 average production increased 12.7 percent on a per BOE per day basis over 2009 which includes the production from the February 2010 sale of the Pinto property of approximately 60 BOE per day and the November 2009 sale of the Shaunavon property of approximately 200 BOE per day. Crude oil production increased by 23.4 percent while gas production decreased by 5.4 percent. The natural gas decrease was due primarily to the shut in of a portion of the Company's Pembina natural gas production. In June 2010, a non-operated natural gas plant, to which Bonterra delivers a portion of its natural gas, reached capacity and resulted in the shut in of a number of the Company's natural gas wells. The average amount of shut in natural gas during Q3 was approximately 660 MCF per day (110 BOE per day).

Effective October 1, 2010, the Company was notified of additional shut in requirements due to other owners in the plant increasing their throughput. Although Bonterra is an owner in the facility, the Company had been delivering natural gas volumes well in excess of its ownership percentage. The amount of natural gas shut in effective October 1, 2010 was approximately 1,100 MCF per day (183 BOE per day) net to the Company. The Company is currently reviewing alternatives, while considering the current low natural gas prices, to either redirect this natural gas production or participate with the other owners in the plant in the expansion of the facility. A short-term solution has been presented by one of the other owners where they would redirect a portion of their natural gas to an alternative natural gas processing facility. Once this is complete, anticipated by the end of Q1 2011, Bonterra would be able to reactivate all of its currently shut in production, but due to low natural gas prices may elect to keep these wells shut in for the present time.

The Company drilled 22 gross (20.0 net) operated Pembina Cardium horizontal oil wells (five gross and net in Q4 2010) and one gross and net Pembina Cardium vertical oil well during 2010. The Company also participated in the drilling of five gross (0.75 net) (two gross and 0.3 net in Q4 2010) non-operated Pembina Cardium horizontal oil wells and two gross (0.3 net) non-operated Pembina Cardium vertical oil wells during 2010. Bonterra's working interest in the non-operated wells is approximately 15 percent. Bonterra had a 100 percent success rate in 2010.

As of December 31, 2010 the Company had four gross (3.75 net) operated horizontal wells drilled but not on production. One of the remaining operated horizontal oil wells (one net) was placed on production January 2, 2011. The remaining three (2.75 net) horizontal wells were on production in February, 2011.

The Company's fourth quarter 2010 production saw increases in crude oil of 488 barrels per day and a decline in natural gas of 460 MCF per day production compared to Q3 2010. During the fourth quarter, the Company was able to place on production two 100 percent gross and net horizontal wells in October, four gross (3.43 net) horizontal wells in November and one gross and net horizontal well in late December, 2010. Offsetting the increase in solution gas from these wells was the additional shut in of approximately 600 MCF per day of natural gas production due to the above mentioned gas plant capacity restrictions.

Bonterra expects 2011 production to average between 6,200 and 6,500 BOE per day.

REVENUE

	Three Months Ended			Twelve Months Ended	
	December 31, 2010	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Revenue – oil and gas sales ($ 000s)	**34,209**	28,332	24,946	**118,980**	85,712
Average Realized Prices:					
Crude oil and NGLs ($ per barrel)	**75.91**	68.79	68.40	**72.69**	59.82
Natural gas ($ per MCF)	**3.78**	3.74	4.76	**4.14**	4.15

Revenue from petroleum and natural gas sales increased 38.8 percent in 2010 compared to 2009. The increase was primarily due to a 23.4 percent increase in crude oil production as well as a 21.5 percent increase in crude oil prices. During 2010 the Company did not enter into any risk management contracts.

Quarter over quarter the Company saw an increase in revenues of $5,877,000, a 20.7 percent increase, due primarily to increased crude oil production as well as increased crude oil pricing.

ROYALTIES

	Three Months Ended			Twelve Months Ended	
($ 000s except $ per BOE)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Crown royalties	**2,092**	1,907	1,451	**7,562**	4,737
Freehold royalties, gross overriding royalties and net carried interests	**757**	1,041	892	**3,875**	2,677
Total royalty expense	**2,849**	2,948	2,343	**11,437**	7,414
Percentage of revenue	**8.3**	10.4	9.4	**9.6**	8.6
$ per BOE	**5.09**	5.65	5.22	**5.57**	4.07

Royalties paid by the Company consist primarily of Crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia. The Company's average Crown royalty rate was approximately 6.4 percent (2009 – 5.5 percent) and approximately 3.3 percent (2009 – 3.1 percent) for other royalties.

The fourth quarter royalties decreased $99,000 over the third quarter. During the fourth quarter the Company reviewed several of its other royalty agreements and discovered some overpayments. The adjustment recorded in Q4 2010 amounted to approximately $160,000 of overpayments in previous periods. In addition, production subject to the freehold royalty rate of 17 percent has been declining while production from the Company's new crown horizontal wells, which have a five percent royalty rate, has increased resulting in an overall lower royalty expense.

ALBERTA GOVERNMENT COMPETITIVENESS REVIEW

On March 11, 2010, the Government of Alberta announced it will modify conventional oil and natural gas royalties effective January 2011 to increase Alberta's competitiveness in the upstream energy sector. The current five percent front-end royalty rate on conventional oil and natural gas will become a permanent feature of the royalty system. The maximum royalty rate for conventional oil will be reduced to 40 percent from 50 percent. The maximum royalty rate for conventional and unconventional natural gas will be reduced at higher prices from 50 to 36 percent. Other royalty incentive programs will remain in effect. Management believes these changes to the royalty system should have a positive effect on the Company's future cash flow.

OTHER REVENUE

	Three Months Ended			Twelve Months Ended	
($ 000s)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Investment tax credit recovery	**–**	–	27,670	**–**	27,670
Gain on sale of property	**–**	700	24,198	**6,485**	24,198
Gain on sale of investments	**782**	3,536	–	**4,335**	–
Interest and other	**10**	2	95	**36**	158
Total other revenue	**792**	4,238	51,963	**10,856**	52 026

As part of the Company's conversion from a trust to a corporation in 2008, Bonterra assumed approximately $27,670,000 of investment tax credits (ITC's) from SRX Post holdings Inc. Due to the depressed commodity prices as of December 31, 2008, the Company was not able to justify the ability to claim these ITC's prior to their expiration. The recovery in the price of crude oil as well as the Company's success in its horizontal crude oil development has resulted in significantly higher future anticipated cash flow from Bonterra's oil and gas operations and therefore justified that the ITC's are likely to be claimed in the future. The Company was able to do so in 2009.

On November 6, 2009, the Company closed the sale of a portion of its Shaunavon oil production to Eagle Rock Exploration Ltd. (Eagle Rock) (TSXV: ERX). The proceeds of disposition consisted of $23,729,000 cash and 30,769,200 common shares in Eagle Rock (representing approximately 4.2 percent of the outstanding common shares of that company at the time). The closing price of the Eagle Rock common shares on November 6, 2009 was $0.21 resulting in total consideration for the property of $30,191,000. The book value (net of asset retirement provision) of the property to the Company was approximately $5,993,000 resulting in a gain on sale of $24,198,000. Eagle Rock has since changed its name to Wild Stream Exploration Inc. (Wild Stream) (TSXV: WSX) and consolidated its common shares on a 30:1 basis.

In February 2010, the Company disposed of its Southeast Saskatchewan Pinto property. The proceeds of disposition were $5,534,000 cash. At the time of disposition, the Company had a net book value of $120,000 for the property and had an asset retirement obligation related to the property of $371,000 that was transferred resulting in a gain on sale of property of $5,785,000. In addition, during the third quarter of 2010 the Company disposed of non-producing land for proceeds of $700,000. The Company had no capital costs associated with this land.

Effective July 6, 2010, Comaplex Minerals Corp. (Comaplex) (a company with common directors and management with the Company) was acquired by Agnico-Eagle Mines Limited (Agnico-Eagle) (TSX: AEM). In exchange for Bonterra's 689,682 common shares in Comaplex, the Company received 689,682 shares in Geomark Exploration Ltd. (Geomark) (TSXV: GME) (a company with common directors and management with the Company) and 108,693 common shares in Agnico-Eagle. The value of the Agnico-Eagle shares is included with investments while the value of the Geomark shares is listed as investment in related party on the December 31, 2010 balance sheet.

During 2010, Bonterra disposed of a portion of its investments. Gross proceeds from the sales were $5,603,000 resulting in an accounting gain of $4,335,000. The Company holds in excess of $11,000,000 worth of investments as of December 31, 2010.

PRODUCTION COSTS

		Three Months Ended		Twelve Months Ended	
($ 000s except $ per BOE)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Production costs	**8,699**	8,069	6,870	**30,451**	27,848
$ per BOE	**15.55**	15.47	15.30	**14.82**	15.28

Total production costs in 2010 have increased by $2,603,000 over 2009. The increase is substantially due to approximately $2.5 million in 2007, 2008 and 2009 natural gas processing fee adjustments billed to Bonterra during 2010 by the operator of several of the natural gas plants that the Company uses to process its natural gas. On a per BOE basis, production costs have declined in 2010 compared to 2009 by $0.46, and excluding the natural gas processing fee adjustments, by $1.66 mainly due to higher rate horizontal wells, field optimization and cost control procedures implemented by Bonterra.

Total operating costs increased in the fourth quarter of 2010 compared to the prior quarter due primarily to the billing of 2009 natural gas processing charge adjustments of approximately $800,000 (see above discussion).

GENERAL AND ADMINISTRATIVE EXPENSE

		Three Months Ended		Twelve Months Ended	
($ 000s except $ per BOE)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
G&A Expense	**1,468**	1,204	1,623	**5,406**	4,458
$ per BOE	**2.62**	2.31	3.61	**2.63**	2.45

General and administrative (G&A) expenses increased 21.3 percent in 2010 compared to 2009. The Company provides administrative services to Geomark and Pine Cliff Energy Ltd. (Pine Cliff) (TSXV: PNE), companies that share common directors and management. Please refer to discussion under Related Party Transactions for details.

The Company's significant general and administrative costs include employee compensation; professional services such as legal, engineering and accounting; computer services, bank charges and occupancy costs. Employee compensation expense increased by approximately 21 percent ($742,000) in 2010 from 2009 due to a larger bonus accrual and an increase in staff. The Company's bonus plan consists of cash payments equal to three percent of before tax net earnings (excluding the 2009 investment tax credit recovery of $27,670,000) to be paid to employees and key consultants. Bonus payments to individuals are based on performance. Costs associated with professional services were relatively unchanged year over year. Costs associated with computer services (decrease of $72,000) and bank charges (decrease of $43,000) were offset by increased occupancy cost of $138,000.

The quarter over quarter increase of $264,000 was primarily due to increased employee and consultant compensation.

During the year the Company capitalized $Nil (2009 – $460,000) of general and administrative costs.

INTEREST EXPENSE

	Three Months Ended			Twelve Months Ended	
($ 000s except $ per BOE)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Interest on long-term debt	**654**	562	620	**2,244**	2,833
Other interest	**192**	140	118	**555**	461
Interest Expense	**846**	702	738	**2,799**	3,294
$ per BOE	**1.51**	1.35	1.64	**1.35**	1.81

Bank debt at December 31, 2010 was $70,386,000 (December 31, 2009 – $59,823,000). The Company's banking arrangements allow it to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one half percent lower than that charged on the general loan account.

The Company has also borrowed $32,000,000 (December 31, 2009 – $23,500,000) from two related parties as well as $15,000,000 (December 31, 2009 – Nil) from a private investor. Please see Related Party Transactions and Liquidity and Capital Resources sections for further details.

Interest charges decreased in 2010 as decreased interest rates more than overset the increase in average outstanding debt balance. The interest rate decrease is due to a reduced bank rate resulting from a better debt to cash flow ratio and to increases in loans from related parties and private investments which have a lower interest rate than bank loans.

Quarter over quarter saw an increase in interest charges due to increased debt balances resulting from the Company's fourth quarter capital program.

Effective April 9, 2010, the Company renewed its bank facility under similar terms and conditions with the exception of extending the revolving period to April 27, 2012, reducing its interest and bank fees and amending one of the material covenants (see below).

The interest rate on the credit facility is calculated as follows:

	Level I	Level II	Level III	Level IV	Level V
Consolidated Total Funded Debt (1) to Consolidated Cash flow Ratio	Under 1.0:1	Over 1.0:1 to 1.5:1	Over 1.5:1 to 2.0:1	Over 2.0:1 to 2.5:1	Over 2.5:1
Canadian Prime Rate Plus (2)	100	150	175	200	250
Bankers' Acceptances Rate Plus (2)	225	275	300	325	375

(1) Consolidated total funded debt excludes related party amounts and subordinated debenture but includes working capital. Consolidated cash flow is calculated as cash flow according to GAAP excluding adjustments for non-cash working capital items.

(2) Numbers in table represent basis points.

Consolidated total funded debt to consolidated cash flow ratio shall be calculated each fiscal quarter and the interest rates adjusted effective as of the first day of the fiscal quarter commencing immediately after the fiscal quarter in which Bonterra files a compliance certificate containing the ratio, with each such adjustment to be effective until the next such adjustment.

As of December 31, 2010 the Company will continue to qualify for the Level I interest rates.

The following is a list of the material covenants of the Company's bank facility:

- The Company is required to not exceed $120,000,000 in consolidated debt (includes negative working capital but excludes debt to related parties and the subordinated promissory note). As of December 31, 2010 the Company had consolidated total funded debt of $52,995,000.
- Total dividends paid in the current quarter and the three previous quarters shall not exceed 80 percent of the previous four quarters' cash flow as defined under GAAP. Dividend payments totalled $46,867,000 during the quarter and the three previous quarters while cash flow totalled $68,782,000 during the same period for an overall payout ratio of 68 percent.

STOCK-BASED COMPENSATION

Stock-based compensation is a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. The Company issued only 36,000 stock options during 2010 resulting in a reduction of stock-based compensation by $428,000. As of December 31, 2010, the Company has a total of $290,000 of stock-based compensation to amortize over the next two years.

The 36,000 common share options were issued with a weighted average exercise price of $36.98 per share and a fair value of $5.67 per option. The fair value of the options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 1.9 percent (2009 – 1.4 percent), expected weighted average volatility of 33 percent (2009 – 33 percent), expected weighted average life of 2.8 years (2009 – 3.0 years) and an annual dividend rate based on the dividends paid to the shareholders during the year.

DEPLETION, DEPRECIATION, ACCRETION AND DRY HOLE COSTS

The Company follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Company depletes its oil and natural gas intangible assets using the unit-of-production basis by field.

For tangible assets such as well equipment, the Company now uses a 10 percent declining basis for depreciation calculation. The Company changed from the straight line basis due to the increasing reserve life index which continues to indicate a longer service life for its production assets.

Provisions are made for asset retirement obligations through the recognition of the fair value of obligations associated with the retirement of tangible long-life assets being recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

At December 31, 2010, the estimated total undiscounted amount required to settle the asset retirement obligations was $62,579,000 (2009 – $64,482,000). The $1,903,000 decrease is due primarily to a reduction in anticipated inflation from two percent to one and a half percent.

These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of five percent. The discount rate is reviewed annually and adjusted if considered necessary. A change in the rate would have a significant impact on the amount recorded for asset retirement obligations. Based on the current provision, a one percent increase in the risk adjusted rate would decrease the asset retirement obligation by $2,827,000, while a one percent decrease in the risk adjusted rate would increase the asset retirement obligation by $3,875,000.

The above calculation requires an estimation of the amount of the Company's petroleum reserves by field. This figure is calculated annually by an independent engineering firm and is used to calculate depletion. This calculation is to a large extent subjective. Reserve adjustments are affected by economic assumptions as well as estimates of petroleum products in place and methods of recovering those reserves. To the extent reserves are increased or decreased, depletion costs will vary.

For the fiscal year ending December 31, 2010, the Company expensed $22,278,000 (2009 – $19,277,000) for the above-described items. The increase is predominately due to increased production volumes resulting from the Company's Pembina Cardium horizontal oil well drill program. The higher BOE depletion charges on the horizontal wells are primarily due to lack of production history on these wells resulting in lower proved reserves being assigned but with substantial probable reserves being assigned. The Company's policy is to deplete the cost of the wells based on proved reserves. When there is longer production history on the horizontal wells there may be a conversion of the probable reserves to proven reserves which would result in a reduction of depletion charges per BOE in future years.

The Company continues to have relatively low finding and development costs. Based on year end reserves, the Company's average cost of proved reserves is $7.80 (2009 – $6.62) per BOE.

The Company currently has an estimated reserve life for its proved developed producing reserves of 10.1 (2009 – 11.7) years calculated using the Company's gross reserves (prior to allowance for royalties) based on the third party engineering report dated December 31, 2010 and using fourth quarter 2010 average production rates of 6,080 BOE per day (2009 – 4,879 BOE per day). Based on total proved reserves the Company has a 12.9 (2009 – 14.2) year reserve life and on a proved and probable basis the reserve life increases to 17.8 (2009 – 20.1) years. These figures are some of the longest reserve life indexes (excluding oil sands) in the Canadian oil and gas industry.

TAXES

The current tax provision relates to a resource surcharge of $141,000 (2009 – $282,000) payable to the Province of Saskatchewan. The resource surcharge is calculated as a flat percent of revenues generated from the sale of petroleum products produced in Saskatchewan. The resource surcharge rate is three percent in 2010. In 2009, a capital tax amount of $269,000 payable to the Province of Quebec was incurred due to the 2008 reorganization for the conversion from a Trust to a Corporation. The capital tax payable to the Province of Quebec was a one-time charge.

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	20-100	$ 25,441
Eligible capital expenditures	7	6,849
Share issue costs	20	1,424
Canadian oil and gas property expenditures	10	19,074
Canadian development expenditures	30	109,642
Canadian exploration expenditures	100	11,140
SR&ED expenditures	100	39,985
Income tax losses carried forward [1]	100	222,596
		$ 436,151

(1) Income tax losses carried forward expire in the following years; 2024 – $3,347,000, 2025 – $7,532,000, 2026 – $46,671,000, 2027 – $117,189,000, 2028 – $34,726,000, 2029 – $13,131,000.

In addition to the above pools, the Company also has $27,670,000 (December 31, 2009 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 – $3,469,000, 2020 – $3,059,000, 2021 – $4,667,000, 2022 – $3,909,000, 2023 – $3,155,000, 2024 – $1,995,000, 2025 – $2,257,000, 2026 – $2,405,000, 2027 – $2,009,000, 2028 – $745,000.

The Company also has $141,417,000 (December 31, 2009 – $143,061,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results and its future acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the future income tax asset.

NET EARNINGS

	Three Months Ended			Twelve Months Ended	
($ 000s except $ per share)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Net Earnings	**14,213**	12,724	52,136	**49,864**	68,563
$ per share – Basic	**0.75**	0.68	2.88	**2.65**	3.81
$ per share – Fully Diluted	**0.73**	0.66	2.85	**2.58**	3.78

Bonterra's net earnings for the year ended December 31, 2010 represents a 27.3 percent decrease over the Company's 2009 net earnings. Two significant factors contributing to the 2009 net earnings were the Company's recordings of the investment tax credit recovery of $27,670,000 and the sale of a portion of the Company's Shaunavon production for a gain of $24,198,000; all of which occurred in the fourth quarter of 2009. Excluding these items (net of 29.15 percent tax effect), 2009 net earnings would decrease by $36,748,000 from $68,563,000 to an adjusted net earnings of $31,815,000. In 2010, a gain on sale of property of $4,665,000 (net of 28.06 percent tax effect) was incurred. Excluding these items, Bonterra's 2010 net earnings increased by $13,384,000, or 42 percent, over 2009.

Higher revenues resulting from increased production and increased commodity prices were the main reason for the significant net earnings increase. The Company continues to return in excess of 40 percent of its gross crude oil and natural gas revenues in net earnings. The Company's low capital costs per BOE of reserves combined with the Company's low production decline rates should allow for continued positive earnings.

OTHER COMPREHENSIVE INCOME

Other comprehensive income for 2010 consists of an unrealized gain before tax on investments (including investments in a related party) of $8,602,000 (2009 – $697,000) including a fourth quarter unrealized gain before tax of $2,642,000 relating to an increase in the investment's fair value. The Company also sold some of these investments, which comprise of marketable securities, for a realized gain before tax of $4,335,000 (2009 – $Nil) including a fourth quarter realized gain before tax of $782,000. Realized gains decrease other comprehensive income, as the gains are transferred to net earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments including the investment in Geomark, net of tax.

CASH FLOW FROM OPERATIONS

	Three Months Ended			Twelve Months Ended	
($ 000s except $ per share)	**December 31, 2010**	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
Cash flow from operations	**16,987**	17,558	13,673	**66,262**	38,893
$ per share - basic	**0.89**	0.93	0.76	**3.52**	2.16
$ per share fully diluted	**0.86**	0.91	0.75	**3.42**	2.15

Cash flow from operations increased 70 percent year over year, mainly due to increased production and crude oil prices. Fourth quarter cash flow decreased by $571,000 over Q3 due to adjustments of $3,335,000 relating to changes in non-cash working capital items. The Company has not entered into any risk management agreements and as such is fully exposed to changes in commodity prices and exchange rates.

CASH NETBACKS

The following table illustrates the Company's annual cash netback:

($ per BOE)	**2010**	2009
Production volumes (BOE)	**2,054,375**	1,822,628
Gross production revenue	**$ 57.92**	$ 47.04
Royalties	**(5.57)**	(4.07)
Production costs	**(14.82)**	(15.28)
Field netback	**37.53**	27.69
General and administrative	**(2.63)**	(2.45)
Interest and taxes	**(1.43)**	(2.11)
Cash netback	**$ 33.47**	$ 23.13

The following table illustrates the Company's cash netback for the three months ended:

($ per BOE)	December 31, 2010	September 30, 2010
Production volumes (BOE)	**559,400**	521,601
Gross production revenue	**$ 61.15**	$ 54.32
Royalties	**(5.09)**	(5.65)
Production costs	**(15.55)**	(15.47)
Field netback	**40.51**	33.20
General and administrative	**(2.62)**	(2.31)
Interest and taxes	**(1.58)**	(1.39)
Cash netback	**$ 36.31**	$ 29.50

RELATED PARTY TRANSACTIONS

As a result of the acquisition of Comaplex by Agnico-Eagle, the loan agreement and Bonterra common shares previously held by Comaplex were transferred to Geomark. A new management agreement was entered into between Bonterra and Geomark with the only amendment to the former agreement with Comaplex being a reduction in the monthly management fee from $30,000 to $22,500.

Geomark and Comaplex combined paid a management fee to the Company of $316,500 (2009 – $330,000). Geomark also shares office rental costs and reimburses the Company for costs related to employee benefits and office materials. In addition, Geomark owns 204,633 (Comaplex December 31, 2009 – 204,633) common shares in the Company. Services provided by the Company included executive services (chief executive officer, president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed were charged at estimated fair value. At December 31, 2010, Geomark owed the Company $35,000 (Comaplex December 31, 2009 – $105,000).

As of December 31, 2010, Geomark has loaned the Company $20,000,000 (Comaplex December 31, 2009 – $12,000,000). The loan is unsecured, bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms. The loan cannot be repaid, or demanded to be paid by Geomark, unless the Company has sufficient available borrowing limits under the Company's credit facility. Interest paid on both the Comaplex and Geomark loans during 2010 was $313,000 (2009 – $194,000). This loan results in being a substantial benefit to Bonterra and to Geomark. The interest paid to Geomark by Bonterra is substantially lower than bank interest and for Geomark, the interest earned is substantially higher than Geomark would receive by investing in bank instruments such as BA's or GIC's.

The Company also has a management agreement with Pine Cliff. Pine Cliff has common directors and management with the Company. Pine Cliff paid a management fee to the Company of $90,000 (2009 – $120,000). Services provided by the Company include executive services (CEO, president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. The Company has no share ownership in Pine Cliff. At December 31, 2010, the Company had an account receivable from Pine Cliff of $1,000 (December 31, 2009 – $1,000).

As of December 31, 2010, the Company's CEO and major shareholder has loaned the Company $12,000,000 (December 31, 2009 – $11,500,000). The loan is unsecured, bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms. The loan cannot be repaid, or demanded to be paid by the Company's CEO, unless the Company has sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan during 2010 was $242,000 (2009 – $209,000). This loan results in being a substantial benefit to Bonterra and to the CEO. The interest paid to the CEO by Bonterra is substantially lower than bank interest and for the CEO, the interest earned is substantially higher than the CEO would receive by investing in bank instruments such as BA's or GIC's.

LIQUIDITY AND CAPITAL RESOURCES

During 2010, the Company incurred capital costs of $76,914,000 (2009 – $28,726,000) net of drilling tax credits. The costs relate primarily to the drilling, completing, tie-in and equipping of 22 gross (20.0 net) operated Pembina Cardium horizontal wells as well as its proportion of the non-operated drilling costs. During the fourth quarter of 2010, Bonterra elected to drill two additional operated horizontal oil wells and the operator of non-operated property also added two additional (0.3 net to Bonterra) horizontal oil wells to its drilling program.

The Company currently has plans to spend approximately $50,000,000 to $60,000,000 on its 2011 Pembina Cardium horizontal well program and non-operated capital programs. Bonterra anticipates funding the 2011 capital program out of cash flow, proceeds from the exercise of employee stock options, sale of investments and the Company's line of credit.

As of December 31, 2010 and December 31, 2009, the Company has a bank facility consisting of a $100,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. Amounts drawn under these facilities at December 31, 2010 were $70,386,000 (December 31, 2009 – $59,823,000). The interest rates on the outstanding debt as of December 31, 2010 were 4.0 percent and 3.4 percent on the Company's Canadian prime rate loan and Bankers' Acceptances, respectively. For information related to interest rate levels and material covenants please refer to the discussion under Interest Expense.

On October 4, 2010, the Company borrowed $15,000,000 from a private investor. In exchange Bonterra has issued a Subordinated Promissory Note for $15,000,000. The terms of the Subordinated Promissory Note are that it bears interest at three percent, is not callable by the investor prior to January 4, 2012 at which time it will be a demand note until its maturity of April 4, 2012, and can be repaid at the option of the Company at any time. Security consists of a floating demand debenture totaling $15,000,000 over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company.

The Company is authorized to issue an unlimited number of common shares without nominal or par value. Transactions during the years 2010 and 2009 in the shares of the common stock of the Company are as follows:

	2010		2009	
	Number	**Amount ($ 000s)**	Number	Amount ($ 000s)
Common Shares				
Balance, beginning of year	**18,619,641**	**121,955**	17,257,603	99,530
Issued pursuant to private placement	–	–	1,068,000	17,996
Issued on acquisition of Cobalt (Note 4)	–	–	201,438	3,207
Issued pursuant to Company share option plan	**599,900**	**12,377**	92,600	1,898
Transfer of contributed surplus to share capital	–	**698**	–	103
Issue costs for private placement	–	–	–	(1,046)
Future tax effect of share issue costs	–	–		267
Balance, end of year	**19,219,541**	**135,030**	18,619,641	121,955

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,921,954 common shares (2009 – 1,861,964). The exercise price of each option granted equals the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2010 and 2009, and changes during the twelve month periods ended on those dates is presented below:

	December 31, 2010		December 31, 2009	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	**1,330,900**	**$ 20.36**	1,390,500	$ 20.50
Options granted	**36,000**	**36.98**	33,000	14.90
Options cancelled	**(20,000)**	**34.66**	–	–
Options exercised	**(599,900)**	**20.63**	(92,600)	20.50
Outstanding at end of period	**747,000**	**$ 20.56**	1,330,900	$ 20.36
Options exercisable at end of period	**255,500**	**$ 20.50**	370,900	$ 20.50

The following table summarizes information about options outstanding at December 31, 2010:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/10	Weighted-Average Remaining Contractual Life	Weighted-Average Price	Number Exercisable at 12/31/10	Weighted-Average Exercise Price
$ 14.90	22,000	2.1 years	$ 14.90	–	$ –
20.50	719,000	1.9 years	20.50	255,500	20.50
48.60	6,000	2.5 years	48.60	–	–
$ 14.90 - $ 48.60	747,000	1.9 years	$ 20.56	255,500	$ 20.50

COMMITMENTS

The Company has no contractual obligations that last more than a year other than its office lease agreements which are as follows:

Lease Obligations ($000s)	
Year 1	$ 967
Year 2	874
Year 3	537
Year 4	–
Year 5	–
Total	$ 2,378

FINANCIAL REPORTING UPDATE

International Financial Reporting Standards (IFRS)

In October 2009, the Accounting Standards Board issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to apply IFRS, in full and without modification, for all financial periods beginning January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Bonterra for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

The Company commenced the process to transition its financial statements from current Canadian GAAP to IFRS in 2008. The Company's project consists of three key phases: the scoping and diagnostic phase, the impact analysis and evaluation phase and the implementation phase.

- Scoping and diagnostic phase – this phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis were given a priority ranking according to their complexity and the amount of time required to assess the impact of changes in transitioning to IFRS. The Company identified the following high impact and medium impact areas:

  High impact areas:

  - IFRS 1 – First time adoption of IFRS
  - IFRS 3 – Business combinations
  - IAS 16 – Property and equipment
  - IAS 36 – Impairment of assets

  Medium impact areas include:

  - IFRS 6 - Exploration and evaluation of mineral resources
  - IFRS 2 – Share-based payments
  - IAS 1 – Presentation of financial statements
  - IAS 10 – Events after the balance sheet date
  - IAS 12 – Income Taxes
  - IAS 18 – Revenues
  - IAS 23 – Borrowing costs
  - IAS 39 – Financial instruments, recognition and measurement
  - IAS 37 Provisions, contingent liabilities and contingent assets

- Impact analysis and evaluation phase – during this phase, items identified in the diagnostic were addressed according to the priority ranking assigned to them. The Company conducted analysis of policy choices allowed under IFRS and their impact to the financial statements. Additionally, certain potential differences were further investigated to assess if there was any broader impact to the Company's net earnings, debt agreements, compensation arrangements or management reporting systems. The impact analysis and evaluation phase was concluded by management pending the Audit Committee of the Board of Directors approval on all accounting policies chosen by management. Since Bonterra uses successful efforts method of accounting on its petroleum and natural gas properties under Canadian GAAP, the audit committee of the Board of Directors gave management the directive to chose policies that will retain as much comparability to the accounting policies chosen under Canadian GAAP.
- Implementation phase – involved implementation of all changes approved in the impact analysis and evaluation phase, which included minor changes to existing information systems, the creation of new business processes and the modification of training staff impacted by the conversion.

Since its inception, the project has been led by the financial reporting group with sponsorship from the executive team. The Company has effectively completed all phases of its IFRS transition project and continues to review its draft IFRS financial statements and disclosures for completeness and quality assurance. The Audit Committee will review and approve the Company's IFRS accounting policy selections and adjustments prior to the release of the first quarter of 2011 financial statements and MD&A.

First Time Adoption of IFRS

Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet presented, based on standards applicable at that time. IFRS 1 provides entities adopting IFRS for the first time with certain optional exemptions and mandatory exceptions to the general requirement for full retrospective application of IFRS. Management has analyzed the various accounting policy choices available under IFRS 1 and has implemented those determined to be the most appropriate for Bonterra. Accordingly, it has applied the following IFRS 1 exemptions in its IFRS opening balance sheet:

- Business combinations (IFRS 1) – provides the option to apply IFRS 3, Business Combinations, retrospectively or prospectively from the Transition Date. The retrospective basis would require restatement of all business combinations that occurred prior to the Transition Date. The Company elected not to retrospectively apply IFRS 3 to business combinations that occurred prior to its Transition Date and such business combinations have not been restated. Any goodwill arising on such business combinations before the Transition Date has not been adjusted from the carrying value previously determined under Canadian GAAP as a result of applying these exemptions.

- Share-based payments (IFRS 2) – encourages the application of its provisions to equity instruments granted on or before November 7, 2002, but permits the application only to equity instruments granted after November 7, 2002 that had not vested by the Transition Date. The Company elected to avail itself of the exemption provided under IFRS 1 and applied IFRS 2 for all equity instruments granted after November 7, 2002 that had not vested by its Transition Date. Further, the Company applied IFRS 2 for all liabilities arising from share-based payment transactions that existed at its Transition Date. This election has no material effect on the Company.
- Borrowing Costs (IAS 23) – requires an entity to capitalize the borrowing costs related to all qualifying assets for which the commencement date for capitalization is on or after January 1, 2010. Due to the short time frame to drill a well and place it on production this election has no material effect on the Company.
- Leases (IAS 17) – requires an entity to assess arrangements outstanding at the Transition Date. It also requires a determination of the appropriate lease classification in accordance with IAS 17, should an arrangement containing a lease be identified as part of the International Financial Reporting Interpretations Committee (IFRIC) 4, Determining Whether an Arrangement Contains a Lease, application. This election has no effect on the Company.
- Decommissioning Liabilities Included in the Cost of Property, Plant and Equipment (IAS 37) – Provisions, Contingent Assets and Contingent Liabilities requires an entity to estimate the statutory and constructive liabilities that existed at the Transition Date, discounted at the risk free rate. The Company has revalued its asset retirement obligation under GAAP to IFRS. The Company also determined it had no unrecorded statutory or constructive obligations.

The following is a listing of key areas where accounting policies differ and where accounting policy decisions are necessary that will significantly impact our reported financial position and results of operations:

- Deferred credit – On November 12, 2008, Bonterra Energy Income Trust (the "Trust") was acquired by Bonterra Oil & Gas Ltd. through a reverse takeover by the Trust of SRX Post Holdings Inc. (SRX). This transaction gave the Company additional tax pools in excess of the purchase price. Under Canadian GAAP this purchase was considered an acquisition of an asset and not a business combination and therefore the resulting gain on acquisition had to be deferred and charged to net earnings on the same basis as the acquired assets. Under IFRS the deferred gain does not meet the definition of a liability and the deferred credit of $55,131,000 ($7,363,000 of the deferred credit being a current liability) is recorded as a decrease to deficit.

- Asset exchange revaluation – In 2007, the Company exchanged certain oil and gas assets in Alberta for oil and gas assets in Saskatchewan that were recorded at book value under Canadian GAAP. Under IFRS the values of the assets received are to be recorded at fair value, this resulted in \$14,310,000 increase in the cost of the property and equipment and a \$2,553,000 increase in the accumulated depletion and amortization of the property and equipment on the January 1, 2010 opening balance sheet. As a result of this change, the Company's deferred tax asset decreased by \$3,446,000 million and the net offset is recorded as a decrease to deficit.
- Asset retirement obligation (ARO) – Under IFRS, the Company is required to revalue its entire liability for asset retirement costs at each balance sheet date using a current liability-specific discount rate, which can generally be interpreted to mean the current risk-free rate of interest. Under Canadian GAAP, obligations are discounted using a credit-adjusted risk-free rate and, once recorded, the asset retirement obligation is not adjusted for future changes in discount rates. At January 1, 2010 Bonterra's total of its asset retirement obligations will increase by \$3,492,000 to \$21,282,000 from \$17,790,000, as the liability is revalued to reflect the estimated risk free rate of interest at that time of 4.1 percent. The offsetting ARO asset cost will be adjusted by \$3,540,000 due to the changes in the ARO liability. The ARO asset would also incur \$1,804,000 more accumulated depletion. As a result of these changes, Bonterra's deferred tax asset is increased by \$442,000 and the net offset is recorded as an increase to deficit.
- Future income tax asset (liability) – Under Canadian GAAP, Bonterra separates future income tax assets (liabilities) between current, which as of January 1, 2010 was a \$11,889,000 asset and long-term, which as of January 1, 2010 was a \$58,265,000 asset. Under IFRS, all future income tax assets (liabilities) (which will be renamed "deferred tax") will all be classified as long-term.
- Impairment of property and equipment (P&E) assets – Canadian GAAP generally uses a two-step approach to impairment testing; first comparing asset carrying values with undiscounted future cash flows to determine whether an impairment exists, and then measuring impairment by comparing asset carrying values to their fair value (which is calculated using discounted cash flows). IFRS uses a one-step approach for testing and measuring impairment, with asset carrying values compared directly with the higher of fair value less costs to sell and value in use down to a cash generating unit (CGU) level. A cash generating unit is the smallest group of assets that generates cash flows largely independent of other assets or group of assets. The impairment test categories of CGUs under IFRS is materially similar to the impairment groupings already chosen under Canadian GAAP, since the Company is using the successful efforts method of accounting for its P&E assets. The discount rate however, to determine fair value could materially differ under IFRS versus Canadian GAAP. As of January 1, 2010 and December 31, 2010, the Company does not anticipate an impairment of P&E assets under IFRS.

The table below summarizes the Company's January 1, 2010 balance sheet under Canadian GAAP and the transitional entries required to present the opening balance sheet under IFRS. Bonterra has not yet prepared a full set of annual financial statements under IFRS, therefore, amounts disclosed are unaudited.

($ 000s)	Canadian GAAP	IFRS Adjustments	IFRS
Current assets	39,569	(11,889)	27,680
Long-term assets	254,418	21,919	276,337
Total assets	**293,987**	**10,030**	**304,017**
Current liabilities	49,731	(7,363)	42,368
Long-term liabilities	125,382	(44,277)	81,105
Equity	118,874	61,670	180,544
Total liabilities and equity	**293,987**	**10,030**	**304,017**

In addition to accounting policy differences, the Company's transition to IFRS is expected to impact its internal control over financial reporting, disclosure controls and procedures, certain of Bonterra's business activities and IT systems as follows:

- Internal control over financial reporting (ICFR) – Bonterra is currently in the process of reviewing its ICFR documentation and is identifying instances where controls must be amended or added in order to address the accounting policy changes required under IFRS. No material changes in control procedures are expected as a result of transition to IFRS.
- Disclosure controls and procedures – Bonterra has assessed the impact of transition to IFRS on its disclosure controls and procedures and has not identified any material changes required in its control environment. It is expected that there will be increased note disclosure around certain financial statement items than what is currently required under Canadian GAAP. Management is currently drafting its IFRS note disclosure in accordance with current IFRS standards and continues to monitor requirements put forth by the International Accounting Standards Board (IASB) in discussion papers and exposure drafts for future disclosure requirements. Throughout the transition process, Bonterra has carefully considered its stakeholders' information requirements and will continue to ensure that adequate and timely information is provided to meet these needs.
- Business activities – Management has been cognizant of the upcoming transition to IFRS, and as such, has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the changes to the Company's accounting policies, no issues are expected to arise with the existing wording of debt covenants and related agreements as a result of the conversion to IFRS.

- IT systems – Bonterra has completed the accounting system updates required in order to prepare for IFRS reporting. Since the Company has been using successful efforts method to account for its petroleum and natural gas assets, no significant modifications were deemed critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010.

BUSINESS PROSPECTS, RISKS AND OUTLOOKS

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry and increasing environmental controls and regulations. The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Company's cash flow or in the value of its producing and non-producing oil and natural gas properties.

The Company presently attempts to minimize these risks by pursuing both oil and natural gas activities and operates its oil and natural gas interests in areas which have long life reserves, where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

SENSITIVITY ANALYSIS

Sensitivity analysis, as estimated for 2011:

	Cash Flow	Cash Flow Per Share (1)
U.S. $1.00 per barrel	$ 1,376,000	$ 0.072
Canadian $0.10 per MCF	$ 349,000	$ 0.018
Change of Canadian $0.01/U.S. $ exchange rate	$ 1,161,000	$ 0.060

(1) Based on year end outstanding common shares of 19,219,541.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on www.sedar.com as well as on the Company's website at www.bonterraenergy.com.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditor's report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink
Chief Executive Officer
March 22, 2011

Garth E. Schultz
Chief Financial Officer
March 22, 2011

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Bonterra Energy Corp.

We have audited the accompanying consolidated financial statements of Bonterra Energy Corp., which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of shareholders' equity, operations and deficit, comprehensive income and cash flow for the years then ended, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Bonterra Energy Corp. as at December 31, 2010 and 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta
March 22, 2011

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ 000s)	2010	2009
ASSETS		
Current		
Accounts receivable (Note 14)	**17,345**	14,713
Crude oil inventory	**487**	431
Prepaid expenses	**1,631**	3,247
Future income tax asset (Note 10)	**22,889**	11,889
Investments (Note 5 and 6)	**11,471**	4,462
Investment in related party (Note 5)	**–**	4,827
	53,823	39,569
Investment in related party (Note 5)	**814**	
Restricted cash	**–**	812
Investment tax credit receivable (Note 10)	**27,670**	27,670
Future income tax asset (Note 10)	**30,011**	58,265
Property and Equipment (Note 6)		
Petroleum and natural gas properties and related equipment	**332,141**	255,840
Accumulated depletion and depreciation	**(109,315)**	(88,169)
Net Property and Equipment	**222,826**	167,671
	335,144	293,987
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**16,839**	18,868
Due to related parties (Note 7)	**32,000**	23,500
Deferred credit (Note 10)	**19,586**	7,363
	68,425	49,731
Subordinated promissory note (Note 8)	**15,000**	-
Bank debt (Note 9)	**70,386**	59,823
Deferred credit (Note 10)	**25,850**	47,769
Asset retirement obligations (Note 11)	**17,070**	17,790
	196,731	175,113
Commitments, Contingencies and Guarantees (Note 16)		
Shareholders' Equity (Note 12)		
Share capital	**135,030**	121,955
Contributed surplus	**3,135**	3,350
	138,165	125,305
Deficit	**(5,454)**	(8,451)
Accumulated other comprehensive income (Note 13)	**5,702**	2,020
	248	(6,431)
Total Shareholders' Equity	**138,413**	118,874
	335,144	293,987

See the accompanying notes to the consolidated financial statements

On behalf of the Board:

George F. Fink
Director

Bill Woodward
Director

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

For the Years Ended December 31 ($ 000s)	2010	2009
Shareholders' equity, beginning of year	**118,874**	56,777
Comprehensive income for the year	**53,546**	69,163
Common Shares issued pursuant to private placement	–	17,217
Common Shares issued on acquisition	–	3,207
Common Shares issued pursuant to Company share option plan	**12,377**	1,898
Stock-based compensation expense	**483**	911
Dividends declared	**(46,867)**	(30,299)
Shareholders' Equity, End of Year	**138,413**	118,874

CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT

For the Years Ended December 31 ($ 000s except $ per share)	2010	2009
Revenue and Other Income		
Oil and gas sales	**118,980**	85,712
Royalties	**(11,437)**	(7,414)
Investment tax credit recovery	–	27,670
Gain on sale of property (Note 6)	**6,485**	24,198
Gain on sale of investments	**4,335**	–
Interest and other	**36**	158
	118,399	130,324
Expenses		
Production costs	**30,451**	27,848
General and administrative	**5,406**	4,458
Interest on long-term debt (Notes 8 and 9)	**2,244**	2,833
Other interest (Note 7)	**555**	461
Stock-based compensation	**483**	911
Depletion, depreciation and accretion	**22,278**	19,277
	61,417	55,788
Earnings Before Taxes	**56,982**	74,536
Taxes (Note 10)		
Current	**141**	551
Future	**6,977**	5,422
	7,118	5,973
Net Earnings for the Year	**49,864**	68,563
Deficit, beginning of year	**(8,451)**	(46,715)
Dividends declared and paid	**(46,867)**	(30,299)
Deficit, end of year	**(5,454)**	(8,451)
Net Earnings Per Share – Basic (Note 12)	**2.65**	3.81
Net Earnings Per Share – Diluted (Note 12)	**2.58**	3.78

See the accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31 ($ 000s except $ per share)	2010	2009
Net Earnings for the Year	**49,864**	68,563
Other comprehensive income net of income tax		
Unrealized gains on investments (net of income taxes of 1,192, (2009 – 97))	**7,410**	600
Realized gains on investments transferred to net earnings (net of income taxes of 607 (2009 – Nil))	**(3,728)**	
Other Comprehensive Income	**3,682**	600
Comprehensive Income	**53,546**	69 163
Comprehensive Income Per Share – Basic (Note 12)	**2.85**	3 84
Comprehensive Income Per Share – Diluted (Note 12)	**2.77**	3 81

See the accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOW

For the Years Ended December 31 ($ 000s)	2010	2009
Operating Activities		
Net earnings for the year	**49,864**	68,563
Items not affecting cash		
Stock-based compensation	**483**	911
Depletion, depreciation and accretion	**22,278**	19,277
Gain on sale of property	**(6,485)**	(24,198)
Gain on sale of investments	**(4,335)**	
Future income taxes	**6,977**	5,422
	68,782	69,975
Change in non-cash working capital		
Accounts receivable	**(2,590)**	(47)
Crude oil inventory	**(39)**	365
Prepaid expenses	**1,616**	1,057
Accounts payable and accrued liabilities	**(1,313)**	(4,654
Restricted cash	**812**	440
Investment tax credit receivable	**–**	(27,670)
Asset retirement obligations settled (Note 11)	**(1,006)**	(573)
	(2,520)	(31,082)
Cash Provided by Operating Activities	**66,262**	38,893
Financing Activities		
Increase (decrease) in debt	**10,563**	(35,613)
Due to related parties	**8,500**	17,500
Subordinated promissory note	**15,000**	–
Issue of shares pursuant to private placement	**–**	17,996
Share issue costs	**–**	(1,046)
Stock option proceeds	**12,377**	1,898
Dividends	**(46,867)**	(30,299)
Cash Used in Financing Activities	**(427)**	(29,564)
Investing Activities		
Property and equipment expenditures	**(76,914)**	(28,726)
Proceeds on sale of properties	**6,234**	23,729
Proceeds on sale of investments	**5,603**	–
Restricted term deposit	**–**	20
Change in non-cash working capital		
Accounts receivable	**(42)**	(3,613)
Accounts payable and accrued liabilities	**(716)**	(739)
Cash Used in Investing Activities	**(65,835)**	(9,329)
Net cash inflow	**–**	–
Cash, beginning of year	**–**	–
Cash, End of Year	**–**	–
Cash Interest Paid	**2,799**	3,294
Cash Taxes Paid	**152**	616

See the accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 2010 and 2009

1. CHANGE OF ORGANIZATION

Effective January 1, 2010, Bonterra Energy Income Trust, a wholly owned Trust of Bonterra Oil & Gas Ltd., was wound up into its parent and was amalgamated with Bonterra Energy Corp., a former subsidiary of the Trust. The continuing entity officially changed its name to Bonterra Energy Corp. ("Bonterra" or the "Company") subsequent to finalizing the reorganization.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) as described below.

Consolidation

These consolidated financial statements include the accounts of the Company, the Trust (wholly owned by the Company as of December 31, 2009 and wound up on January 1, 2010) and its wholly owned subsidiary Bonterra Energy Corp. (amalgamated with the Company on January 1, 2010). Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the balance sheets as well as the reported amounts of revenues, expenses, and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts.

Amounts recorded for depletion, depreciation, accretion and amounts used for impairment calculations are based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves. Stock-based compensation is based upon expected volatility and option life estimates. Asset retirement obligations are based on estimates of abandonment costs, timing of abandonment, inflation and interest rates. The provision for income taxes is based on judgements in applying income tax law and estimates on the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. These estimates are subject to measurement uncertainty and changes in these estimates could materially impact the financial statements of future periods.

Revenue Recognition

Revenues associated with sales of petroleum and natural gas are recorded when title passes to the customer.

Joint Interest Operations

Significant portions of the Company's oil and gas operations are conducted jointly with other parties and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Inventories

Inventories consist of crude oil. Crude oil stored in the Company's tanks are valued on a first in first out basis at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, royalties and depletion and depreciation for the year and net realizable value is determined based on estimated sales price less transportation costs.

Investments

Investments are carried at fair value. Fair value is determined by multiplying the year end trading price of the investments by the number of common shares held at period end.

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Company follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs including geological and geophysical costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Producing properties are assessed annually or more frequently as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

Costs related to undeveloped properties are excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. These properties are assessed at least annually to determine whether impairment has occurred.

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit-of-production method. Development and exploration drilling costs are depleted over the remaining proved reserves.

On January 1, 2010, the Company prospectively began depreciating petroleum and natural gas plant and equipment using the declining balance method at 10 percent per year, a change from the straight-line method. The change of estimate was due to declining balance depreciation providing a better reflection of the estimated service life of the related assets. During 2010, the Company incurred $2,000,000 less depreciation under the declining balance method, than under the straight-line method.

Furniture, Equipment and Other

On January 1, 2010, the Company prospectively began depreciating these assets using the declining balance method at rates of 10 percent to 30 percent per year, a change from the straight-line method. The change of estimate was due to declining balance depreciation providing a better reflection of the estimated service life of the related assets. During 2010, the Company incurred $141,000 less depreciation under the declining balance method, than under the straight-line method.

Income Taxes

The Company accounts for income taxes using the liability method. Under this method, the Company records a future income tax asset or liability to reflect any difference between the accounting and tax basis of assets and liabilities, using substantively enacted income tax rates. The effect on future tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change occurs. Future income tax assets are only recognized to the extent it is more likely than not that sufficient future taxable income will be available to allow the future income tax asset to be realized.

Asset Retirement Obligations

The Company recognizes an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. On a periodic basis, management will review these estimates and changes, if any, will be applied prospectively. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the obligations are charged against the ARO to the extent of the liability recorded.

Stock-Based Compensation

The Company accounts for stock based compensation using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Stock-based compensation expense is recorded over the vesting period with a corresponding amount reflected in contributed surplus. Stock-based compensation expense is calculated as the estimated fair value of the options at the time of grant, amortized over their vesting period. When stock options are exercised, the associated amounts previously recorded as contributed surplus are reclassified to common share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: held-for trading, loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. Held-for-trading financial instruments are measured at fair value and changes in fair value are recognized in net earnings. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

All risk management contracts are recorded in the balance sheet at fair value unless they qualify for the normal sale and normal purchase exemption. All changes in their fair value are recorded in net earnings unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net earnings. Any hedge ineffectiveness is immediately recognized in net earnings. The Company has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties-resulting in all changes in fair value being recorded in net earnings.

Accounts receivable are classified as loans and receivables which are measured at amortized cost. Investments and investments in related party are classified as available-for-sale which are measured at fair value and any gains or losses are recognized in other comprehensive income in the period they occur. Accounts payable and accrued liabilities, bank debt, subordinated promissory note and amounts due to related parties are classified as other financial liabilities, which are measured at amortized cost.

Risk Management Contracts

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in earnings in the period they occur.

The Company may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and the Company has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy for undertaking hedge transactions. During the years ended December 31, 2010 and December 31, 2009, the Company did not designate any of its financial instruments as hedges. There are no risk management contracts outstanding at December 31, 2010 and December 31, 2009.

Basic and Diluted per Share Calculations

Basic earnings per share are computed by dividing earnings by the weighted average number of shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options to purchase shares were exercised. The treasury stock method is used to determine the dilutive effect of common share options, whereby proceeds from the exercise of common share options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

3. RECENT ACCOUNTING PRONOUNCEMENTS

The Canadian Accounting Standards Board has confirmed that IFRS will replace Canadian GAAP effective January 1, 2011, including comparatives for 2010, for Canadian publicly accountable enterprises.

4. BUSINESS COMBINATIONS

On July 2, 2009, the Company acquired all of the issued common shares of Cobalt Energy Ltd. (Cobalt) for consideration of 201,438 common shares at a value of $15.92 per common share plus the assumption of $2,856,000 of negative working capital for total consideration of $6,063,000. Results of Cobalt's operations have been included in the consolidated financial statements commencing from that date.

The acquisition was accounted for using the purchase method and the purchase price was allocated to the fair value of the assets acquired and the liabilities assumed as follows:

($ 000s)	
Cost of acquisition	
Value of common stock	3,207
Acquisition costs	170
	3,377
Allocation of purchase price:	
Property and equipment	7,105
Future income tax liability	(748)
Working capital deficiency	(2,856)
Asset retirement obligations	(124)
	3,377

5. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 common shares in Geomark Exploration Ltd. (Geomark), a company having common directors and management with the Company. The investment is recorded at fair market value.

Effective July 6, 2010, Comaplex Minerals Corp. (Comaplex) (a company having common management and directors) was acquired by Agnico-Eagle Mines Limited (Agnico-Eagle). In exchange for Bonterra's 689,682 common shares in Comaplex, the Company received 689,682 shares in Geomark and 108,693 common shares in Agnico-Eagle (value included in Investments on the balance sheet). The investment in Geomark represents 1.3 percent ownership in the outstanding common shares of Geomark.

6. PROPERTY AND EQUIPMENT

	2010		2009	
($ 000s)	**Cost**	**Accumulated Depletion and Depreciation**	Cost	Accumulated Depletion and Depreciation
Undeveloped land	**4,595**	**–**	7,992	–
Petroleum and natural gas properties and related equipment	**326,072**	**108,217**	246,387	87,153
Furniture, equipment and other	**1,474**	**1,098**	1,461	1,016
	332,141	**109,315**	255,840	88,169

On November 6, 2009, the Company divested of a portion of its Shaunavon oil production to Eagle Rock Exploration Ltd. (Eagle Rock). The proceeds of disposition consisted of $23,729,000 cash and 30,769,200 common shares in Eagle Rock (representing approximately 4.2 percent of the outstanding common shares of that company at that time). The Eagle Rock common shares were trading for $0.21 cents per share on November 6, 2009. The Company had a net book value (after effects of asset retirement obligations) of $5,993,000 attributable to the assets disposed of resulting in a gain on sale of the property of $24,198,000.

Eagle Rock has since changed its name to Wild Stream Exploration Inc. (Wild Stream) and consolidated its common shares on a 30:1 basis resulting in Bonterra holding 1,025,640 common shares (value included in Investments on the balance sheet).

In February 2010, the Company disposed of its Southeast Saskatchewan Pinto property. The proceeds of disposition were $5,534,000 cash. At the time of disposition, the Company had a net book value of $120,000 for the property. It also had an asset retirement obligation related to the property of $371,000 that was transferred resulting in a gain on sale of property of $5,785,000.

In July 2010, the Company disposed of non-producing land rights for proceeds of $700,000. The Company has never had any capital costs associated with these land rights.

During the year the Company capitalized $Nil (2009 – $460,000) of general and administrative costs.

7. DUE TO RELATED PARTIES

As of December 31, 2010, the Company's CEO and major shareholder has loaned the Company $12,000,000 (December 31, 2009 – $11,500,000). The loan is unsecured, bears interest at a Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Interest paid on this loan during 2010 was $242,000 (2009 – $209,000).

As a result of the acquisition by Agnico-Eagle of Comaplex on July 6, 2010, the $12,000,000 loan previously held by Comaplex was transferred to Geomark and is repayable by the Company under the same terms. As of December 31, 2010, Geomark has loaned the Company $20,000,000. The loan is unsecured, bears interest at a Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Interest paid on this loan during 2010 was $313,000 (including interest paid to Comaplex) (2009 – $194,000 paid to Comaplex).

The Company's bank agreement requires that the above loans can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. As of December 31, 2010, the Company has sufficient room to repay all balances.

Please refer to Note 14 for additional related party transactions.

8. SUBORDINATED PROMISSORY NOTE

On October 4, 2010 the Company borrowed $15,000,000 from a private investor. In exchange Bonterra has issued a Subordinated Promissory Note for $15,000,000. The terms of the Subordinated Promissory Note are that it bears interest at three percent, is not callable by the investor prior to January 4, 2012 at which time it will be a demand note until its maturity of April 4, 2012, and can be repaid at the option of the Company at any time. Security consists of a floating demand debenture totaling $15,000,000 over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on the subordinated promissory note during 2010 was $110,000.

The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. As of December 31, 2010 the Company has sufficient room to repay the subordinated promissory note.

9. BANK DEBT

As of December 31, 2010, the Company has a bank facility consisting of a $100,000,000 syndicated and $20,000,000 non-syndicated revolving credit facility (December 31, 2009 – $100,000,000 syndicated and $20,000,000 non-syndicated revolving credit facility). The interest rates on the outstanding debt as of December 31, 2010 were 4.0 percent and 3.4 percent on the Company's Canadian prime rate loan and Bankers' Acceptances, respectively. The terms of the syndicated revolving credit facility provided that the loan is revolving to April 27, 2012 and is subject to annual review. The revolving credit facility has no fixed payment requirements. The Company at December 31, 2010 was in level I (see below) in respect of its various borrowing charges.

The amount available for borrowing under the credit facility is reduced by outstanding letters of credit. Letters of credit totaling $285,000 were issued at December 31, 2010 (December 31, 2009 – $285,000). Security for the credit facilities consists of various fixed and floating demand debentures totaling $200,000,000 over all of the Company's assets, and a general security agreement with first ranking over all personal and real property.

The interest rate on the credit facility is calculated as follows:

	Level I	Level II	Level III	Level IV	Level V
Consolidated Total Funded Debt [1] to Consolidated Cash flow Ratio	Under 1.0:1	Over 1.0:1 to 1.5:1	Over 1.5:1 to 2.0:1	Over 2.0:1 to 2.5:1	Over 2.5:1
Canadian Prime Rate Plus [2]	100	150	175	200	250
Bankers' Acceptances Rate Plus [2]	225	275	300	325	375

(1) Consolidated total funded debt excludes related party amounts and subordinated debenture but includes working capital. Consolidated cash flow is calculated as cash flow according to GAAP excluding adjustments for non-cash working capital items.

(2) Numbers in table represent basis points.

Consolidated total funded debt to consolidated cash flow ratio shall be calculated each fiscal quarter and the interest rates adjusted effective as of the first day of the fiscal quarter commencing immediately after the fiscal quarter in which Bonterra files a compliance certificate containing the ratio, with each such adjustment to be effective until the next such adjustment.

The following is a list of the material covenants:

- The Company is required to not exceed $120,000,000 in consolidated total funded debt (includes working capital but excludes due to related parties and subordinated debt).
- The total of the dividends paid in the current quarter and the three previous quarters shall not exceed 80 percent of the previous four quarters' cash flow as defined under GAAP excluding adjustments for non-cash working capital items.

At December 31, 2010, the Company is in compliance with all covenants.

10. INCOME TAXES

The Company has recorded a future income tax asset related to assets and liabilities and related tax amounts:

($ 000s)	2010	2009
Future tax liability related to investments	(832)	(824)
Future tax liability related to property and equipment	(12,347)	(5,855)
Future tax asset related to asset retirement obligations	4,274	4,474
Future tax asset related to finance costs	367	802
Future tax asset related to corporate tax losses and SR&ED claims	37,717	59,668
Future tax asset related to corporate capital tax losses	17,705	17,883
Valuation adjustment	(16,873)	(17,883)
Future Tax Asset – Long-Term	30,011	58,265
Current portion of future income tax asset related to corporate tax losses and SR&ED claims:	22,889	11,889
Future Tax Asset – Current	22,889	11,889

A reconciliation of the deferred credit is as follows:

($ 000s)	
Amount recorded on reorganization	71,303
Amortized in 2008	(4,240)
Amortized in 2009	(12,356)
Rate adjustment 2009	425
Balance as of December 31, 2009	55,132
Amortized in 2010	(9,408)
Rate adjustment 2010	(288)
Balance as of December 31, 2010	45,436
Current portion	19,586
Long-term portion	25,850
	45,436

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

($ 000s)	**2010**	2009
Earnings before income taxes	**56,982**	74,536
Combined federal and provincial income tax rates	**28.06%**	29.15%
Income tax provision calculated using statutory tax rates	**15,989**	21,727
Increase (decrease) in taxes resulting from:		
Saskatchewan resource surcharge	**141**	282
Quebec tax	**–**	269
Stock-based compensation	**136**	266
Deferred credit amortization	**(9,696)**	(11,931)
Non-taxable portion of gains	**(461)**	–
Change in valuation allowance	**(1,010)**	–
Change in effective tax rate	**2,071**	(4,708)
Other	**(52)**	68
Income tax expense	**7,118**	5,973

The Company and its subsidiaries have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	20-100	$ 25,441
Eligible capital expenditures	7	6,849
Share issue costs	20	1,424
Canadian oil and gas property expenditures	10	19,074
Canadian development expenditures	30	109,642
Canadian exploration expenditures	100	11,140
SR&ED expenditures	100	39,985
Income tax losses carried forward [1]	100	222,596
		$ 436,151

(1) Federal income tax losses carried forward expire in the following years; 2024 – $3,347,000, 2025 – $7,532,000, 2026 – $46,671,000, 2027 – $117,189,000, 2028 – $34,726,000, 2029 – $13,131,000.

The Company has $27,670,000 (2009 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 – $3,469,000, 2020 – $3,059,000, 2021 – $4,667,000, 2022 – $3,909,000, 2023 – $3,155,000, 2024 – $1,995,000, 2025 – $2,257,000, 2026 – $2,405,000, 2027 – $2,009,000, 2028 – $745,000.

The Company also has $141,417,000 (December 31, 2009 – $143,061,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, acquisitions and dispositions of assets and liabilities. A significant change in any of these assumptions could materially affect the Company's estimate of the future income tax asset.

11. ASSET RETIREMENT OBLIGATIONS

At December 31, 2010, the estimated total undiscounted amount required to settle the asset retirement obligations was $62,579,000 (2009 – $64,482,000). Costs for asset retirement have been calculated assuming a 1.5 percent inflation rate. These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of five percent (2009 – five percent).

Changes to asset retirement obligations were as follows:

($ 000s)	**2010**	2009
Asset retirement obligations, January 1	**17,790**	18,338
Adjustment to asset retirement obligations	**(220)**	(138)
Adjustment related to asset disposals	**(368)**	(750)
Liabilities settled during the year	**(1,006)**	(573)
Accretion	**874**	913
Asset retirement obligations, December 31	**17,070**	17,790

12. SHAREHOLDERS' EQUITY

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value. The Company is also authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable preferred shares or Class "B" preferred shares.

Issued

	2010		2009	
	Number	**Amount ($ 000s)**	Number	Amount ($ 000s)
Common Shares				
Balance, beginning of year	**18,619,641**	**121,955**	17,257,603	99,530
Issued pursuant to private placement	**–**	**–**	1,068,000	17,996
Issued on acquisition of Cobalt (Note 4)	**–**	**–**	201,438	3,207
Issued pursuant to Company share option plan	**599,900**	**12,377**	92,600	1,898
Transfer of contributed surplus to share capital		**698**		103
Issue costs for private placement		**–**		(1,046)
Future tax effect of share issue costs		**–**		267
Balance, end of year	**19,219,541**	**135,030**	18,619,641	121,955

On May 27, 2009, the Company completed a private placement for 1,068,000 common shares at a price of $16.85 per common share for aggregate proceeds of $17,996,000. The Company incurred issue costs of $1,046,000 in respect of the offering.

The number of common shares used to calculate diluted net earnings per share for the year ended December 31, 2010 of 19,348,991 shares (2009 – 18,131,085) included the basic weighted average number of common shares outstanding of 18,810,355 shares (2009 – 18,006,320) plus 538,636 shares (2009 – 124,765) related to the dilutive effect of common share options.

A summary of the changes to the Company's contributed surplus is presented below:

Contributed Surplus

($ 000s)	**2010**	2009
Balance, beginning of year	**3,350**	2,542
Stock-based compensation expensed (non-cash)	**483**	911
Stock-based options exercised (non-cash)	**(698)**	(103)
Balance, end of year	**3,135**	3,350

The deficit balance is composed of the following items:

($ 000s)	**2010**	2009
Accumulated earnings	**326,609**	276,745
Accumulated cash dividends	**(332,063)**	(285,196)
Deficit	**(5,454)**	(8,451)

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,921,954 common shares (2009 - 1,861,964). The exercise price of each option granted equals the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2010 and 2009, and changes during the years ended on those dates is presented below:

	December 31, 2010		December 31, 2009	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	**1,330,900**	**$ 20.36**	1,390,500	$ 20.50
Options granted	**36,000**	**36.98**	33,000	14.90
Options cancelled	**(20,000)**	**34.66**	–	–
Options exercised	**(599,900)**	**20.63**	(92,600)	20.50
Outstanding at end of period	**747,000**	**$ 20.56**	1,330,900	$ 20.36
Options exercisable at end of period	**255,500**	**$ 20.50**	370,900	$ 20.50

The following table summarizes information about options outstanding at December 31, 2010:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Weighted-Average Number Outstanding at 12/31/10	Weighted-Remaining Contractual Life	Average Exercise Price	Weighted-Number Exercisable at 12/31/10	Average Exercise Price
$ 14.90	22,000	2.1 years	$14.90	–	$ –
20.50	719,000	1.9 years	20.50	255,500	20.50
48.60	6,000	2.5 years	48.60	–	–
$ 14.90 - $ 48.60	747,000	1.9 years	$20.56	255,500	$20.50

The Company records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. In 2010, the Company granted 36,000 stock options with an estimated fair value of $204,000 ($5.67 per option) using the Black-Scholes option pricing model with the following key assumptions:

	2010	2009
Weighted-average risk free interest rate (%)	1.87	1.4
Expected life (years)	2.8	3.0
Weighted-average volatility (%)	33.1	33.0
Dividend yield 2010 and 2009	based on the percentage of dividends paid during the period granted	

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ 000s)	**January 1, 2010**	**Other Comprehensive Income**	**December 31, 2010**
Unrealized gains on available for sale financial assets	**2,020**	**3,682**	**5,702**

($ 000s)	January 1, 2009	Other Comprehensive Income	December 31, 2009
Unrealized gains on available for sale financial assets	1,420	600	2,020

14. RELATED PARTY TRANSACTIONS

The Company received a management fee from Geomark and Comaplex of $316,500 (Comaplex 2009 – $330,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. At December 31, 2010, the Company had an account receivable from Geomark of $35,000 (Comaplex December 31, 2009 – $105,000). Effective July 6, 2010, the Company cancelled its management agreement with Comaplex due to its takeover by Agnico-Eagle.

A new management agreement was entered into with Geomark effective July 6, 2010, under the same terms and conditions as those of the Comaplex agreement except that the monthly fee is $22,500 compared to Comaplex's monthly fee of $30,000.

The Company received a management fee from Pine Cliff Energy Ltd. (Pine Cliff), a company having common directors and management with Bonterra, of $90,000 (2009 – $120,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. At December 31, 2010 the Company had an account receivable from Pine Cliff of $1,000 (December 31, 2009 – $1,000).

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

15. FINANCIAL AND CAPITAL RISK MANAGEMENT

Financial Risk Factors

The Company undertakes transactions in a range of financial instruments including:

- Receivables
- Payables and accrued liabilities
- Common share investments
- Due to related parties
- Bank debt
- Subordinated Promissory Note

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk, and liquidity risk.

The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk management is carried out by senior management under the direction of the Directors of the Company.

The Company may enter into various risk management contracts in accordance with Board approval to manage the Company's exposure to commodity price fluctuations. Currently no risk management agreements are in place. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

Capital Risk Management

The Company's objectives when managing capital, which the Company defines to include shareholders' equity, debt, due to related parties, subordinated promissory note and working capital balances, are to safeguard the Company's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends, debt facilities or issue new shares.

The Company monitors capital on the basis of the ratio of debt to cash flow. This ratio is calculated using each quarter end net debt (total debt adjusted for working capital) and divided by the preceding twelve months cash flow. The Company believes that a debt level of approximately one and a half year's cash flow is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs.

The following section (a) of this note provides a summary of the Company's underlying economic positions as represented by the carrying values, fair values and contractual face values of the Company's financial assets and financial liabilities. The Company's debt to cash flow from operations is also provided.

The following section (b) addresses in more detail the key financial risk factors that arise from the Company's activities including its policies for managing these risks.

The following section (c) provides details of the Company's risk management contracts that are used for financial risk management.

a) Financial assets, financial liabilities and debt ratio

The carrying amounts, fair value and face values of the Company's financial assets and liabilities are shown in Table 1.

Table 1

	As at December 31, 2010		
($ 000s)	**Carrying Value**	**Fair Value**	**Face Value**
Financial assets			
Accounts receivable	**17,345**	**17,345**	**17,445**
nvestments	**11,471**	**11,471**	**N/A**
Investments in related party	**814**	**814**	**N/A**
Financial liabilities			
Accounts payable and accrued liabilities	**16,839**	**16,839**	**16,839**
Due to related parties	**32,000**	**32,000**	**32,000**
Subordinated promissory note	**15,000**	**15,000**	**15,000**
Bank debt	**70,386**	**70,386**	**70,386**

	As at December 31, 2009		
($ 000s)	Carrying Value	Fair Value	Face Value
Financial assets			
Accounts receivable	14,713	14,713	14,873
Investments	4,462	4,462	N/A
Investments in re.ated party	4,827	4,827	N/A
Restricted cash	812	812	812
Financial liabilities			
Accounts payable and accrued liabilities	18,868	18,868	18,868
Due to related parties	23,500	23,500	23,500
Bank debt	59,823	59,823	59,823

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related parties, subordinated promissory note and bank debt on the consolidated balance sheet are carried at amortized cost. Investments and investments in related party are carried at fair value. All of the fair value items are transacted in active markets. Bonterra classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

The net debt and cash flow from operations figures are presented in Table 2.

Table 2

($ 000s)	December 31, 2010
Bank debt	70,386
Due to related parties	32,000
Subordinated promissory note	15,000
Accounts payable and accrued liabilities	16,839
Current assets [(1)]	(30,934)
Net Debt	103,291
Cash flow from operations [(2)]	66,262
Net debt to cash flow from operations	1.56

(1) Current assets include accounts receivable, crude oil inventory, prepaid expenses, and investments.
(2) Cash flow from operations includes annual net earnings less adjustment for, stock-based compensation, depletion, depreciation and accretion, gain on sale of property, gain on sale of investments, future income taxes, changes in non-cash working capital items, and asset retirement obligations settled.

b) Risks and mitigations

Market risk is the risk that the fair value or future cash flow of the Company's financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Company is exposed are discussed below.

Commodity price risk

The Company's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Company's performance and ability to continue with its dividends.

The Company has used various risk management contracts to set price parameters for a portion of its production. Management, in agreement with the Board of Directors, decided that at least in the near term it will discontinue the use of commodity price agreements. The Company will assume full risk in respect of commodity prices.

Interest rate risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. The principal exposure of the Company is on its borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

The Company's debt facilities consist of a $100,000,000 revolving operating line, $20,000,000 demand operating line, a $15,000,000 subordinated promissory note and $32,000,000 due to related parties. The borrowings under these facilities are at bank prime plus or minus various percentages as well as by means of bankers' acceptances (BA's) within the Company's credit facility. The Company manages its exposure to interest rate risk through entering into various term lengths on its BA's but in no circumstances do the terms exceed six months.

Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) net earnings and comprehensive income by $758,000, respectively.

Foreign exchange risk

The Company has no foreign operations and currently sells all its product sales in Canadian currency. The Company however is exposed to currency risk in that crude oil is priced in U.S. currency then converted to Canadian currency. The Company currently has no outstanding risk management agreements. Management, in agreement with the Board of Directors, decided that at least in the near term it will discontinue the use of commodity price agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

Credit risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur a financial loss. The Company is exposed to credit risk on all financial assets included on the balance sheet. To help mitigate this risk:

- The Company only enters into material agreements with credit worthy counterparties. These include major oil and gas companies or major Canadian chartered banks; and
- Agreements for product sales are primarily on 30 day renewal terms.

Of the accounts receivable balance of December 31, 2010 ($17,345,000) and December 31, 2009 ($14,713,000) over 88 (2009 – 87) percent relates to product sales with international oil and gas companies and drilling credits receivable from the province of Alberta.

The Company assesses quarterly, if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2010, there was no impairment provision required on any of the financial assets of the Company due to historical success of realizing financial assets. The Company does have a credit risk exposure as the majority of the Company's accounts receivables are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days notice if payments are not received.

At December 31, 2010, approximately $231,000 or 1.3 percent of the Company's total accounts receivable are aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. The Company actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint venture partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Company subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at December 31, 2010 is $100,000 (December 31, 2009 – $160,000) with the difference being included in general and administrative expenses. There were no accounts written off during the year.

The maximum exposure to credit risk is represented by the carrying amount on the balance sheet. There are no material financial assets that the Company considers past due.

Liquidity risk

Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will not have sufficient funds to continue with its dividends;
- The Company will be forced to sell assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

To help reduce these risks the Company:

- Maintains a portfolio of high-quality, long reserve life oil and gas assets.

The Company has the following maturity schedule for its financial liabilities:

	Recognized on	Payments Due By Period		
($ 000s)	Financial Statements	Less than 1 year	1-3 years	4-5 years
Accounts payable and accrued liabilities	Yes – Liability	16,839	–	–
Due to related parties	Yes – Liability	32,000	–	–
Subordinated promissory note	Yes – Liability	–	5,000	–
Bank debt	Yes – Liability	–	70,386	–
Office leases	No	967	1,411	–
Total		49,806	86,797	–

c) Risk management contracts

The Company has no outstanding risk management contracts.

16. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The Company has no contractual obligations that last more than a year other than its office lease agreements which are as follows:

Lease Obligations ($ 000s)	
Year 1	967
Year 2	874
Year 3	537
Year 4	–
Year 5	–
Total	2,378

17. SUBSEQUENT EVENTS – DIVIDENDS

Subsequent to December 31, 2010, the Company has declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 5, 2011	January 14, 2011	$0.24	January 31, 2011
February 2, 2011	February 15, 2011	$0.24	February 28, 2011
March 2, 2011	March 15, 2011	$0.24	March 31, 2011

NOTES

CORPORATE INFORMATION

BOARD OF DIRECTORS

G.J. Drummond, Nassau, Bahamas
G.F. Fink, Calgary, Alberta
C.R. Jonsson, Vancouver, British Columbia
F. W. Woodward, Calgary, Alberta

OFFICERS

G.F. Fink – Chief Executive Officer and Chairman of the Board
R.M. Jarock – President and Chief Operating Officer
G.E. Schultz – Chief Financial Officer
R.D. Thompson – Vice President, Finance

REGISTRAR & TRANSFER AGENT

Olympia Trust Company, Calgary, Alberta

AUDITORS

Deloitte & Touche LLP, Calgary, Alberta

SOLICITORS

Borden Ladner Gervais LLP, Calgary, Alberta

BANKERS

CIBC, Calgary, Alberta
The Royal Bank of Canada, Calgary, Alberta
Alberta Treasury Branch, Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange, Toronto, Ontario
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